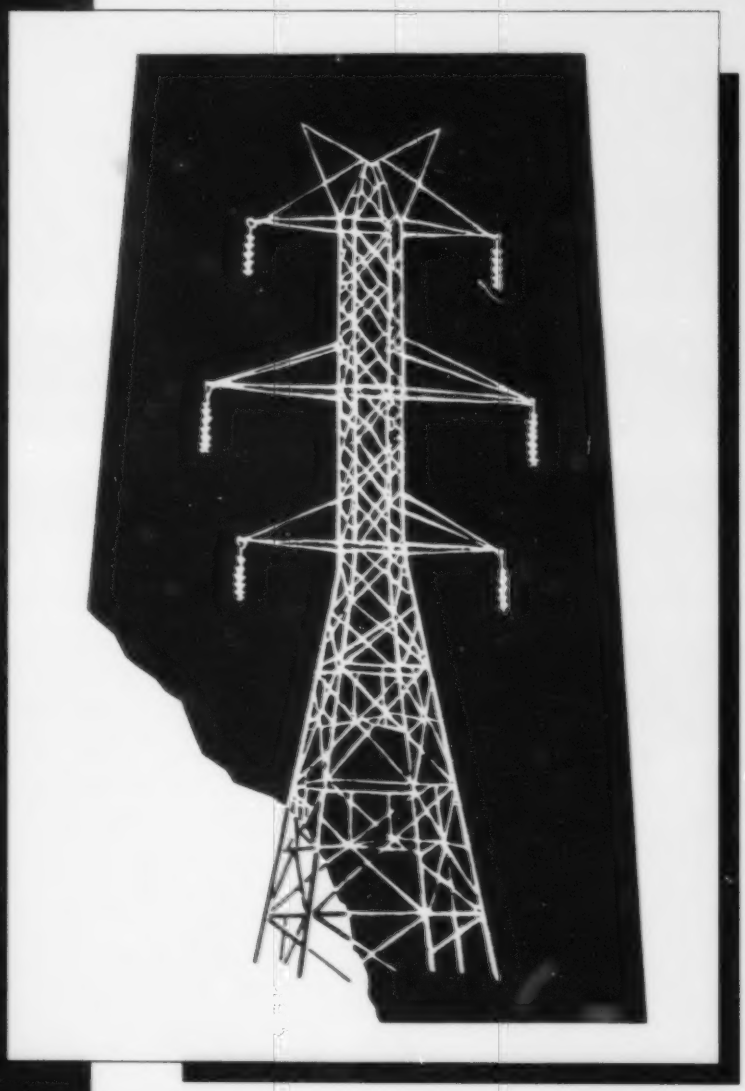
REVIEW OF THE
ALBERTA ELECTRIC ENERGY MARKETING PROGRAM



Prepared by

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November 1991

REVIEW OF THE ALBERTA ELECTRIC ENERGY MARKETING PROGRAM

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REVIEW OF THE ALBERTA ELECTRIC ENERGY MARKETING PROGRAM

ERRATA

Page 26, Table IV-1	-	after heading "Generation & Sales", add **"annual averages".**
Page 32, top table	-	move the Edmonton Power numbers to the right.
Page 43, line 6 (5th full paragraph)	-	the number 0.73 should read **0.72**
Page 44, Table IV-2	-	the "1983-1991 average" column should read (going from the first row under Alberta Power to the last row under Combined Utilities): **5.29, 4.52, 3.27, 3.34, 3.17, 3.37, 3.59, 2.95, 3.08, 3.84, 3.26, 3.16**
Page 45, Table IV-3	-	the "1983-1991 average" column should read (going from the first row under Alberta Power to the last row under Combined Utilities): **-2.02, -1.25, 0.03, 0.20, -0.51, 0.13, -0.68, -0.10**
Page 61, third paragraph, line 2	-	the word "upstream" should be **"downstream".**

March 25, 1992

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* * * * * * *

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November 27, 1991

REVIEW OF THE ALBERTA ELECTRIC ENERGY MARKETING PROGRAM

EXECUTIVE SUMMARY

Background and Objectives

1. In 1982 because of concern about substantial electricity rate differentials across the province between similar consumers, the Alberta Government passed legislation creating the Electric Energy Marketing (EEM) Program.

2. The main purpose of the Program was to establish "fair and equal" wholesale electricity rates for Albertans by averaging utility generation and transmission (G&T) costs. The Program was not designed to equalize retail rates: rates to the ultimate consumer. On average, G&T costs accounted for about 80 percent of total electricity costs.

3. Secondary objectives of the Program included efficient power generation, reductions in the rate of increase in electric energy costs, provision for the import of electric energy, minimal interference in the operations of utilities and the encouragement of more balanced economic growth within Alberta.

4. The Program covered electricity generated by the three main utilities in the province - Alberta Power, Edmonton Power and TransAlta. Medicine Hat opted out of the Program.

5. An Alberta Government "Shielding" Program which terminated in 1989 was introduced to phase in the impact of rate increases under the EEM Program to TransAlta and Edmonton Power customers.

6. The objectives of the EEM Program are broadly consistent with practices elsewhere in Canada to reduce G&T cost differences within individual provinces.

Impact of the EEM Program

7. The wholesale cost of electric energy in Alberta over the past decade has been affected by three government programs, in addition to the EEM Program. These were natural gas price rebates, corporate income tax rebates, and shielding.

8. The collection of key data on G&T costs, on government programs and on EEM Program transfers for Alberta Power, Edmonton Power and TransAlta reveal that provincial average actual G&T costs before adjustments for government programs showed little trend over the last decade. After adjustment for inflation, average G&T costs have fallen.

9. In every year, Alberta Power customers have enjoyed substantial benefits under the EEM Program. The utility's costs are currently about 75 percent of what they would have been without EEM transfers.

10. Edmonton Power became a program beneficiary starting in 1991 after commissioning of a new generation plant. The utility's costs are currently about 80 percent of what they would have been without EEM transfers.

11. TransAlta became a substantial contributor to the EEM Program after 1987. The utility's costs currently exceed what they would have been without EEM transfers by about 20 percent.

Government Payments, Rebates and Direct Costs of the EEM Program

12. Natural gas price rebates terminated in 1983. Income tax rebates to the privately owned utilities (Alberta Power and TransAlta) have been a sizeable $1.9 billion, 1982 to 1991. The shielding program cost to the Government was about $268 million; about $200 million went to TransAlta customers and the remainder to those of Edmonton Power. Total Government payments, rebates, shielding and direct EEM Agency costs over the period of the EEM Program to date have been about $2 billion.

13. Direct Agency costs over its life, at about $3 million, were modest. However, the induced costs of the program to the utilities totalled an estimated $17 million, 1982 to 1990.

Retail Electricity Rates

14. The EEM Program was not intended to equalize retail electricity prices for similar end users. It was confined to equalization of wholesale costs. Nevertheless, the impact of the Program on consumers is important. But a comprehensive provincial survey of retail prices was beyond the scope of the study. Instead, the collection of data was confined to the residential sector for selected areas.

15. The purpose of the exercise was not to make comparisons among utilities, since such comparisons are fraught with difficulty. It is to compare customer costs with and without the EEM Program.

16. The impact of the EEM Program is noticeable at the retail level in the residential sector. For example the spread between Alberta Power's residential rates and those for TransAlta in 1991 show a considerable reduction compared with corresponding numbers in 1982 prior to the EEM Program. The share of wholesale costs in retail rates is considerably lower in the residential sector than for the general service and industrial sectors, suggesting the EEM Program would have a greater relative influence on retail rates in the general service and industrial categories.

Observations

17. To what extent has the main purpose of the program - "fair and equal" wholesale rates - been achieved? In every year of the Program (before shielding) demand and energy charges among the utilities have been equalized. Wholesale costs per unit of electricity within customer classes are the same across the province for loads of equal load factor. This means the objective of "equal" wholesale rates has been met.

18. There is a difference in adjusting for load factors between customer categories. In effect, load factors for residential customers are averaged under the EEM Program and a common wholesale price applies subject only to shielding. Load factors for the general service and industrial categories are not averaged. This treatment is appropriate since the residential classification is more homogeneous than the others and any variations in residential load factors are more involuntary.

19. Shielding tempered the impact on TransAlta and Edmonton Power of cost increases caused by EEM transfers. This added to the acceptability of the Program and contributed to its "fairness", since abrupt imposition of full EEM transfer costs would have been onerous, particularly on TransAlta customers.

20. The achievement of "fair and equal" wholesale rates is illustrated by estimates for 1991.

Wholesale Electric Energy Costs, 1991
¢/kWh

	Alberta Power	Edmonton Power	TransAlta
Residential	4.35	4.35	4.35
General Service	3.59	4.06	3.61
Large Industrial	3.29	3.05	2.93

Unit costs in the residential category are exactly equal. Variations in rates for the other categories are caused by differences in load factors.

21. Achievement of the secondary objectives of the Program including electricity generation efficiency essentially devolved on the utilities themselves and on the other agencies. These included the role of the electric utilities and the Electric Utility Planning Council in coordination and planning, the Energy Resources Conservation Board in approving facility construction, and the Public Utilities Board in approving rates.

22. Functions relating to the import and export of electricity for Alberta also did not devolve on the Agency. The Program did fulfil the objective of minimal interference in utility operations.

23. In 1982, there was an expectation that without the EEM Program, rate differentials - especially between Alberta Power and TransAlta - would widen. However, the data indicate there has been some reduction of differences in aggregate unit costs among the utilities. Thus the underlying problem at least in terms of G&T costs that the EEM Program was intended to solve did not become more acute over the 1980s.

24. Income tax rebates provided a significant cost reduction to the customers of the two privately owned utilities in the absence of the EEM Program and to all customers with the EEM Program.

25. The EEM Program was intended to contribute to more balanced economic growth in the province. While examination of this issue was beyond the scope of the report, industrial electricity sales in the regions served by Alberta Power have grown more rapidly than elsewhere. Although this might have happened anyway, it does suggest that reductions in electricity costs associated with the EEM Program in regions with high costs of electricity may have removed an impediment to growth.

26. The scope of the study did not permit a comprehensive review of the price of electricity paid by final consumers. Retail rates depend not only on the wholesale rates but on a host of other factors including the timing of rate changes, differences in municipal taxes and profits, investment policies, rate design, and customer load characteristics. However, the impact of the EEM Program as seen in the wholesale costs is reflected in the price to the ultimate consumer, albeit subject to variations due to the factors mentioned above.

27. If a full review of final consumer charges were to be pursued, careful adjustments to ensure proper comparisons of retail rates would be required. Such a review might best be carried out by the Government in direct consultation with the utilities.

REVIEW OF THE ALBERTA ELECTRIC ENERGY MARKETING PROGRAM

Introduction

In 1982, the Alberta Government passed legislation creating the Electric Energy Marketing (EEM) Agency. Creation of the Agency reflected concern about electricity rate differentials across the province. The main purpose of the Agency was to reduce wholesale costs differentials by averaging utility generation and transmission rates; i.e. the wholesale rates to the distributing utilities. Such costs on average accounted for about 80 percent of the cost of electricity to ultimate consumers.

The Consultants were asked to review the EEM Program and advise on whether and if so to what extent the Program met its objectives. We were specifically asked not to provide recommendations since the study is intended to assist a Review Panel of the EEM Program which the Honourable Rick Orman, Minister of Energy, Alberta proposes to appoint at a later date.

We have not considered detailed procedures including forecasts, public hearings, adjustments orders and the like of the EEM Agency or the Public Utilities Board (PUB). However, in addition to the impact of the Program on the wholesale costs of the three main utilities, Alberta Power Limited, Edmonton Power and TransAlta Utilities Corporation, the direct and induced costs of the Program and related Alberta Government payments and rebates are indicated. The impact of the EEM Program on typical Alberta residential customers is also reviewed.

The report contents are as follows. Section I provides background information on the origins and objectives of the EEM Program and briefly reviews equalization policies in other provinces. Section II describes the legislation and regulations governing the EEM Program; Section III reviews the structure and operations of the EEM Agency.

The main burden of the report is the evaluation of the impact of the EEM Program on the Alberta electric industry pursued in Section IV. Part A looks at generation and transmission rates for the utilities on a with and without EEM Program basis. Electricity related government payments and rebates are looked at in Part B. Part C outlines the direct and indirect costs of the EEM Program including estimates of induced costs to the utilities of compliance with EEM Agency regulations.

Section V discusses the impact of the EEM Program on typical residential electric energy customers. A final Section (VI) presents the Consultants' observations on the Program.

Two appendices complete the report. Appendix A presents a detailed review of the origins of the EEM Program. Appendix B provides tables containing key annual generation and transmission data for the three utilities (and on a combined basis) for the period 1982 to 1991.

I. BACKGROUND INFORMATION

This Section provides background information on the Electric Energy Marketing (EEM) Program. Part A discusses the origins of the EEM Program;[1] Part B outlines its mission and objectives. Electricity rate equalization policies in other provinces are the subject of Part C.

A. THE ORIGINS OF THE EEM PROGRAM

Alberta Government concerns about intra-provincial electricity rate differentials, expressed in late 1980, had begun to surface in the mid 1970s and earlier.

In 1979 the Alberta Department of Utilities & Telephones commissioned a study by Foster Research of Calgary on the electric utility industry. Study topics were quite wide-ranging including rate differentials, natural gas price rebates, regulation of utility earnings, franchise area allocations, future hydro-electric developments, participation in the western power grid, Rural Electric Association (REA) problems, future ownership for new generation of transmission facilities, and export opportunities.

Initial government thinking on remedies to some or all of the identified problems covered a broad spectrum: eventual take-over of the electric utilities; merger of the electric utilities; introduction of new taxes; and development of new publicly owned electric generation facilities. However, from quite an early stage attention focused on the possibility of what was referred to initially as a Provincial Wholesale Power Marketing Commission, subsequently called the Electric Energy Marketing Agency.

In 1980 the kinds of principles that should govern such a body were drawn up. The prime objective was to reduce rate differentials across the province by equalization of costs at the end of major transmission lines. In other words, any averaging of electricity rates in the province would be confined to generation and transmission (G&T) costs. These were seen, on average, as constituting about 80 per cent of total electricity costs to the consumer. In addition to rate equalization, as many as eight other objectives for the Agency were put forward from time to time before

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[1] Extensive detail on the genesis of the EEM Program is presented in Appendix A.

the Agency came into existence.[2]

When the Government was considering setting up the Agency, it recognized that an averaging process, if immediately initiated in full, would result in substantial changes in certain customer rates. In particular, consumers served by Alberta Power Limited (Alberta Power) would enjoy considerable relief while those served by TransAlta Utilities Corporation (TransAlta), which accounted for about 60 per cent of all the electric energy generated in the province, would suffer considerable increases. While sharp decreases in rates would undoubtedly be popular, large increases would not be so palatable. Therefore the Government decided that the impact of sharp rises should be softened by subsidies to provide a period of adjustment.

Although the proposed Agency was to focus on electric generation and transmission cost equalization across the province, it would also have other important functions. These included the possibility of acting as a vehicle for government funding of high cost generation facilities, involvement with inter-provincial links and involvement with the Alberta interconnected system to enhance economic dispatch (least cost power generation).

At the same time the Agency was not meant to interfere with the normal functions of the Energy Resources Conservation Board (ERCB), the Public Utilities Board (PUB) or in any direct way with the privately owned utilities. It was also anticipated that equalization of electric energy rates would contribute to more balanced economic growth in the Province. The proposed Agency owed something to the concepts underlying the Alberta Petroleum Marketing Commission, created in the early 1970s.

B. EEM PROGRAM MISSION AND OBJECTIVES

By the summer of 1981 the objectives and operating parameters of the proposed Agency were sufficiently developed to allow the drafting of legislation. A Bill (Bill 92) was introduced in the legislature November 16, 1981. In August of that year, a government-industry, liaison/advisory committee on implementation had been set up.

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[2] See Appendix A, Part 4 for a listing of these objectives.

In mid November 1981, the government put out a News Release on the proposed Electric Energy Marketing Agency. After purchase and resale of electric energy from all Alberta sources, the Agency would set a "standard wholesale rate for Alberta consumers". From among the several objectives put forward from time to time for the Agency, five key goals were listed. These were as follows.

1. "establish 'fair and equal' wholesale electric power rate for Albertans...

2. assure the most efficient use of power sources throughout Alberta...

3. reduce the rate of increase to Alberta consumers in their electric energy costs[3]...

4. allow the purchase of power from outside Alberta...

5. allow the continued operation of utilities in the most efficient manner."[4]

The new Agency was also expected to contribute to the objective of balanced economic growth. Minimal Agency administration costs were anticipated.

Reception of the plan among various municipalities was mixed. As one might expect, those areas served by Alberta Power - the major beneficiaries of such a scheme - were happy. However, those in regions served by TransAlta were not. In particular, concerns were raised by the Cities of Calgary, Red Deer, and Lethbridge that transmission costs incurred within their ambit would not be included in the equalization. Subsequently, provision was made for compensation to these three cities for their transmission facilities.

"Shielding"[5] from rate increases was adopted. Such protection was set at 100 percent in the first year of operation

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[3] This would be done via more efficient purchasing.

[4] See News Release, Government of Alberta, November 16, 1981.

[5] Shielding was included in the Utilities Grants Regulation, Schedule Five, under the Department of Transportation and Utilities Act.

declining to 80 percent in the second year, and with further linear reductions until the shielding was to be terminated in 1987. As discussed later, extensions were made to the Shielding Program so that it survived until May 31, 1989.

While the intent of the Program was to institute a common wholesale cost of electric energy, it was recognized that retail rate differences among utilities would remain as a result of different investment policies, different distribution costs, variations in rate design, etc.

From a quite early stage, the City of Medicine Hat was sceptical about joining the scheme. The City was allowed to opt out on the grounds that it owned the natural gas used as feed stock for its generation facilities. The opting out provision was on a once-and-for-all basis.

The Electric Energy Marketing Act was proclaimed on April 15, 1982.[6] The Agency organization was expected to comprise about eight permanent positions.[7] The Agency's administrative costs were intended initially to be rolled into the average cost of service for electric energy in the Province. However, this idea was not pursued and the costs of the Agency became a direct charge on the Government.

Considerable work was undertaken in the first half of 1982 to draw up the appropriate regulations and deal with the practical problems of implementing the operations of the Agency. Close contacts were established during this period with all the affected parties - utilities, municipalities, and the REA's.

The Agency began operations on September 1, 1982.

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[6] See Section II for a listing of the key provisions of this Act.

[7] As is pointed out in Appendix A, answers to questions raised in the Legislature in late March, 1982 confirmed that the Agency would consist of no more than eight persons during the first five years.

C. EQUALIZATION POLICIES IN OTHER PROVINCES[8]

Highlights of electricity rate setting outside Alberta are given below and in Table I-1.

1. British Columbia

British Columbia is served by two utilities. B.C. Hydro and Power Authority (B.C. Hydro) is government-owned while Kootenay Power and Light Company Ltd., a subsidiary of Cominco Ltd., is investor-owned.

West Kootenay Power serves residential customers in four towns directly and sells electricity wholesale to the municipal utilities of seven towns. These municipal utilities resell it to their residential customers who pay slightly more than customers served directly by West Kootenay Power. Industrial and commercial customers of West Kootenay Power pay standard rates, but similar customers of the municipal utilities pay different rates.

B.C. Hydro and West Kootenay Power operate independently. West Kootenay Power's generation costs are lower than B.C. Hydro's because its facilities are more depreciated; moreover, there are no new facilities planned in the area. There is no equalization plan between the two companies. Thus residential customers of West Kootenay Power pay significantly less than residential customers of B.C. Hydro.

The rest of the province is served by B.C. Hydro. It splits the province into three zones. Zone 1 includes the major metropolitan areas, Zone 2 is the remote northern and coastal areas, and Zone 3 is the city and surrounding area of Fort Nelson. Residential customers in all zones pay the same for the first 3,000 kWh of energy used over a two month period. Beyond 3,000 kWh, Zone 2 customers pay significantly more than Zone 1 customers. Zone 3 customers charges are based on power generation costs predicated on Fort Nelson natural gas feedstock (Zone 3 customers may pay more or less than Zone 1 customers). B.C. Hydro equalizes rates up to 3,000 kWh by subtracting the excess revenue requirement from Zone 2 and adding it to the revenue requirement of all customers.

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[8] Much of the material below was prepared by the Electricity Policy Branch, Department of Energy.

2. Saskatchewan

Saskatchewan has a single publicly owned utility, Saskatchewan Power (SaskPower) Corporation, which serves the whole province and supplies two municipal utilities. The municipal utilities have no restrictions on what they charge their customers. SaskPower's urban and rural residential, commercial and industrial customers pay similar energy rates but pay different monthly (demand) charges.

3. Manitoba

There are two publicly owned electric utilities in Manitoba: Winnipeg Hydro and Manitoba Hydro Electric Board Manitoba Hydro). Winnipeg Hydro serves the central area of the City of Winnipeg; Manitoba Hydro serves the rest of the province, including the suburbs of Winnipeg.

Manitoba Hydro charges slightly different rates among the three zones within its service area. These zones were based on population density. The differences in rates charged are intended to reflect the cost of distribution. Generation and transmission costs are equalized across all zones.

Winnipeg Hydro is required to charge the same rates as Manitoba Hydro charges in Winnipeg. Consequently, retail rates are equalized throughout the City of Winnipeg.

Winnipeg Hydro purchases 65 percent of its electricity from Manitoba Hydro. Manitoba Hydro recovers its supply costs through a Cost Sharing Agreement which pools certain generation and transmission costs between the two utilities.

Winnipeg Hydro's generation is relatively inexpensive given the significant depreciation of facilities. As a result, Winnipeg Hydro generation costs are not included in the cost pool; these costs are 'dedicated'. A portion (approximately 35 percent) of Manitoba Hydro's low cost plants is also 'dedicated' and excluded from the cost pool. Thus, the Manitoba-Winnipeg Hydro cost pool consists of all non-dedicated generation costs plus costs of transmission which connect Manitoba Hydro and Winnipeg Hydro. The sharing of costs is done on the basis of energy use and peak demand similar to the Alberta system, except the pooling is not done in separate consumer groups. The pooling agreement between the two utilities is for a specified term, and is not government policy.

Note that full equalization of generation and transmission costs cannot be attained in Manitoba because of the 'dedication' feature.

4. Ontario

Ontario's electricity requirements are supplied by a single publicly owned utility, Ontario Hydro Corporation (Ontario Hydro). All other utilities in the province are municipally owned and operated and buy electricity from Ontario Hydro to resell to their customers. All residential customers of Ontario Hydro are considered to be rural customers and all residential customers of the municipal utilities are considered to be urban customers.

The Rural Rate Assistance Program discounts all rural residential rates to ensure that the average year round retail residential customer bill is within 15 percent of the average municipal residential bill at 1000 kWh usage per month.

Ontario Hydro forecasts the revenue requirement for urban and rural residential customers on an annual basis. Any difference exceeding 15 percent is allocated to the revenue requirement of all customers.

This figure is somewhat deceiving because it does not take into account the contribution policy of Ontario Hydro or the municipal utilities. Each utility has its own "investment" or "contribution" policy which sets out the amount the utility will contribute toward the cost of connecting new customers to its distribution system (interconnection costs). As a utility reduces the contribution under its investment policy, it lowers its distribution costs and therefore lowers the rates required to recover costs. The total cost of electricity includes the utility's rate and the consumer's initial contribution toward the cost of connecting to the system. The consumer's contribution is included in the cost of residential, farm, commercial and industrial property. Although the exact numbers are not available, it is likely that customers of the municipal utilities contribute more to interconnection costs than do customers of Ontario Hydro.[9] Therefore, the difference between average retail residential and municipal bills is less than 15 percent.

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[9] Based on discussions with Ontario Hydro and municipal utilities.

5. Quebec

HydroQuebec, a Crown corporation, is the only utility in the province which generates electricity. Nine municipal utilities distribute electricity to about four percent of the population. HydroQuebec serves the rest of the province. Municipal utilities purchase their electricity from HydroQuebec and are obliged by law to charge customers no more than what HydroQuebec charges its customers. HydroQuebec charges the municipal utilities high voltage bulk rates so that the municipal utilities can resell at HydroQuebec residential rates and still make a profit. Theoretically, the municipal utilities could charge less than HydroQuebec but in practice this is not done.

Within areas served directly by HydroQuebec all customers in the same end-use category pay the same rates. The revenue requirement is calculated for all customers within each category and rates are set without distinguishing between urban and rural customers.

6. New Brunswick

New Brunswick has a single publicly owned utility, New Brunswick Electric Power Commission, which serves the entire province and supplies the municipal utilities of St. John and Edmonston. Each organization charges slightly different rates. Urban and rural residential customers of New Brunswick Power pay similar energy rates but rural customers pay a slightly higher monthly service charge because of greater distribution costs. Industrial and commercial rates are standard for customers of New Brunswick Power but rates differ for customers of municipal utilities.

7. Nova Scotia

Nova Scotia Power Corporation (Nova Scotia Power), a publicly owned utility, serves the entire province and supplies seven municipal utilities. All the municipal utilities and Nova Scotia Power charge slightly different rates.

Urban and rural residential customers of Nova Scotia Power pay the same rates. Nova Scotia Power calculates the revenue requirement for all residential customers and sets its rates without distinguishing between urban and rural customers.

Industrial and commercial rates are standard for customers of Nova Scotia Power but rates differ for customers of municipal utilities.

8. Prince Edward Island

Maritime Electric Company Limited (Maritime Electric) is an investor owned utility serving the entire province and supplying the municipal utility of Summerside. Within the jurisdiction of Maritime Electric, no rate program exists to equalize rates paid by urban customers of Charlottetown and rural residential customers. However urban residential customers of small towns pay the same rates for energy as rural residential customers, though they pay cheaper monthly service charges. In other words, rate disparities are reduced even though distribution costs are slightly higher for rural residential customers.

Summerside buys most of its electricity from Maritime Electric. All of its customers pay slightly different rates than similar customers of Maritime Electric.

9. Newfoundland

The province of Newfoundland has two utilities: an investor owned utility, Newfoundland Light and Power Company Ltd. (NP), and a publicly owned utility, Newfoundland and Labrador Hydro (NLH). NP serves the majority of customers and purchases most of its electricity from NLH. All residential customers on the island of Newfoundland are required by law to pay the same rates, whether they are urban or rural customers or whether they are served by NP or NLH. Remote residential customers rely on diesel generators and pay the same for the first 700 kWh. After that, their rates increase significantly.

NLH also owns the 5600 MW Churchill Falls Hydro project located in Labrador which sells about 98 percent of its generation to Quebec. Customers in Labrador, including three residential communities and one large industrial customer, receive electricity from Churchill Falls at very low rates. All other large industrial customers are located on the island and are charged a standard rate by NLH. NP charges a standard rate for commercial customers.

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To summarize: in the majority of Canadian provinces, electric energy is supplied by a single utility. The exceptions , in addition to Alberta, are British Columbia, Manitoba and Newfoundland. Only one province - P.E.I. - is served exclusively by a privately owned utility. In three provinces - B.C., Alberta and Newfoundland - there is a mix of ownership among the various utilities. Electric utilities in the remaining six provinces are publicly owned.

B.C. is the only province in which a mechanism has not been implemented to reduce differences in costs of generation and 2transmission. Moreover, B.C. utilities have not generally reduced rate disparities in distributing electricity to various customer groups. However, some equalization of distribution costs has been provided to all residential customers of B.C. Hydro since they pay the same rate for the first 3000 kWh of energy.

Of the nine provinces (including Alberta) where differences in generation and transmission costs are reduced, utilities in five of these provinces have implemented procedures which reduce cost differences in distributing electricity to their residential customers. These are the utilities in Saskatchewan, Manitoba, Ontario, Quebec and Newfoundland. Industrial and commercial customers in three of these provinces - Manitoba, Quebec and Newfoundland - also tend to be charged the same rates. Ontario has equalized distribution costs for its industrial and commercial customers contracting for over 5 MW of electricity.

Those provinces in which only differences in generation and transmission costs (but not distribution costs) are reduced are Alberta, New Brunswick, Nova Scotia and P.E.I.

Table I-1: Policies on Rate Disparities Across Canada

Province	Reduction of Differences in Wholesale Costs Between Utilities		Further Reduction of Rate Disparities by Addressing Distribution Costs			
			Residential		Industrial & Commercial	
B.C.	No	Differences between BC Hydro and West Kootenay Power are not reduced. West Kootenay provides service to around 10% of B.C. electrical consumers.	No	B.C. Hydro also charges different rates within its service area. Residential consumers pay the same rate for only the first 3000 kWh of energy over 2 months.	No	Also B.C. Hydro's rates vary among three geographical zones.
Alta	Yes	EEM Agency	No		No	
Sask	Yes	Crown Utility provides all generation and transmission.	Yes	Utilities tend to charge the same rate.	Yes	Utilities tend to charge the same rates.
Manitoba	Yes	A Cost Sharing Agreement exists between Manitoba Hydro and Winnipeg Hydro.	Yes	However, Manitoba Hydro charges different rates within its service area based on 3 population density zones.	Yes	However, Manitoba Hydro charges different commercial rates within the 3 density zones. Industrial rates are standard.
Ontario	Yes	Crown Utility provides all generation and transmission.	Yes	Rural Rate Assistance Program reduces rate difference between consumers of Ontario Hydro and those of municipal utilities.	No Yes	<5 MW - Consumers are charged urban and rural rates. >5 MW - Rural and urban consumers pay the same rates.
Quebec	Yes	Crown Utility provides all generation and transmission.	Yes	Utilities tend to charge the same rate.	Yes	Utilities tend to charge the same rates as HydroQuebec.

Table I-1 (cont'd): Policies on Rate Disparities Across Canada

Province	Reduction of Differences in Wholesale Costs Between Utilities		Further Reduction of Rate Disparities by Addressing Distribution Costs			
			Residential		Industrial & Commercial	
N.B.	Yes	Crown Utility provides all generation and transmission.	No		No	
Newfld	Yes	With the exception of customers in Labrador	Yes	All consumers, except those in Labrador, pay the same for the first 700 kWh of energy.	Yes	Consumers pay standard rates except those in Labrador.
N.S.	Yes	Crown Utility provides all generation and transmission	No		No	
P.E.I.	Yes	Maritime Electric provides all generation and transmission	No		No	

II. LEGISLATION

This section deals with the legislation governing the operations of the Electric Energy Marketing Agency. The first part concerns the Electric Energy Marketing Act; the second concerns the regulations made under it.

A. THE ELECTRIC ENERGY MARKETING ACT

The Electric Energy Marketing Act of 1982 (the EEM Act), with amendments through December 14, 1984, provided for the establishment of The Electric Energy Marketing Agency (EEM Agency) and sets forth its powers and duties and those of the Public Utilities Board (PUB) in relation to the EEM Program. While the Act itself should be consulted for full details, its key provisions are summarized below.

1. Definitions (Section 1)

   These are mostly common usage. But the "pooling interface" is defined as "the point adjacent to and upstream from the place at which electric energy enters an electric distribution system and that is located pursuant to the regulations."

2. Constitution, Reporting, and Funding of the Agency (Sections 2-9)

   The provisions here are straightforward.

3. Constraints on the Agency

   The Agency shall:

   - "conduct its operations in such a way that the cost of electric energy in Alberta at pooling interfaces in minimized .." (Section 10)

   - "endeavour to conduct its operations in such a way that no profit or loss results to the Agency on its operations as a whole." (Section 10)

4. Powers of the Agency

The Agency may:

- "acquire or purchase electric energy from the owner or operator of a public utility or...from outside Alberta..." (Section 11).

- "sell electric energy only to the owner of a public utility at or upstream from a pooling interface or for removal from Alberta..." (Section 11).

- "act as a principal, agent or broker in connection with the marketing of electric energy" (Section 13).

- "subject to the regulations, set the price ... under which it sells electric energy" (Section 13).

- "enter into agreements with respect to short-term emergency power supplies" (Section 13).

- "enter into agreements that have as their objective the marketing of electric energy between Alberta and any other jurisdictions" (Section 13).

5. Duties of the Owner or Operator of a Public Utility or Electric Distribution Systems to Provide Information

- "...shall provide the Agency with any information, including forecasts, that the Agency requires for the purposes of this Act or the regulations." (Section 12)

6. Duties of PUB

The PUB:

- "...shall set the price or pricing formula in respect of each consumer group at which electric energy shall be sold under section 14 to the Agency during a year...". (Section 13.1(1))

- "...may adjust a price or pricing formula set by the Board under section 13.1 for a prior year..." (Section 13.2(1))

7. Duties of Owners of Electric Energy Entering a Pooling Interface

Owners shall:

- "...sell that electric energy ... to the Agency at the price or under the pricing formula set by the Public Utilities Board..." (Section 14(1))

- "...repurchase all the electric energy it sold to the Agency at the pooling interface and at the price or under the pricing formula set by the Agency." (Section 14(3))

8. Duties of the Agency

The Agency shall:

- "resell the electric energy leaving the pooling interface to the person from whom it was purchased ... at the price or under the pricing formula set by the Agency..." (Section 14(2))

- "...the price or pricing formula set by the Agency ...shall reflect an averaging of prices." (Section 14(5)).

- "...adjust the total sum for which it resells electric energy in respect of that consumer group ...in accordance with the adjustment order and the regulations." (Section 14(6)).

9. Regulations

- "The Lieutenant Governor-in-Council may make regulations for the establishment of a scheme or plan for the orderly marketing of electric energy." (Section 16(1)).

10. Proclamation

- Proclaimed on April 15, 1982.

B. GENERAL REGULATIONS OF THE ELECTRIC ENERGY MARKETING ACT

General Regulations initially made under the provision of the Electric Energy Marketing Act (Alta. Reg. 368/82) were repealed January 1, 1985 and the amended General Regulation (Alta. Reg. 405/84) came into force on that date.

The regulations spell out in considerable detail the responsibilities of and procedures to be followed by owners of electric energy, municipalities, utilities, distribution systems, the Public Utility Board and the Electric Energy Marketing Agency. Little would be gained by summarizing this material and the reader interested in the detail is referred to the General Regulations themselves.

III. STRUCTURE AND OPERATION OF THE EEM AGENCY

This Section presents a brief discussion of the operations of the EEM Agency. Part A addresses organization; Part B outlines the procedures used by the Agency in determining the wholesale cost of electricity in the province.

A. EEM AGENCY ORGANIZATION

The EEM Act provided for the appointment by the Lieutenant Governor in Council of a Chairman for the Agency over a prescribed term. When no Chairman is appointed, the Deputy Minister of the Department responsible for the EEM Program becomes the Chairman.[10] This is the case at the time of writing. The Chairman has the power to set up the staff and offices necessary to perform the functions of the EEM Program and to carry out its mandate.

Originally, the Agency reported to the Department of Utilities and Telecommunications. From 1986 to 1989 it reported to the Department of Transportation and Utilities and in 1990 it began reporting to the Department of Energy.

There were two Agency offices in the province. One has always been in Edmonton. The other was originally in Calgary, the home city of the first Agency Chairman. This office was moved in 1984 when a Chairman from Lethbridge was appointed. It remained in Lethbridge until the Agency was disbanded in 1991.

The staff of the Agency varied between six and eight people, with most of them located in Edmonton. Agency functions at various times in its history have required the employment of a Chairman, an Executive Director/Manager, engineers, accountant/analysts, secretaries and clerks.

Salaries accounted for close to 60 percent of total Agency operating costs in 1983/84 ($269 thousand) rising to about 80 percent in 1990/91 ($283 thousand). The increase in the salary component was largely because total expenses for the Agency actually fell over most of the period. Operating costs as reported in the Agency's Annual Reports were about $466 thousand in the first full fiscal year of operation (1983/84) and decreased to $306

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[10] See Section 2(4) of the EEM Act.

thousand in 1987/88. Thereafter they gradually increased to about $355 thousand[11] in 1989/90. The decrease in the Agency's costs was mostly due to a reduction in responsibilities and activities. In its first few years, Agency staff were involved with PUB proceedings and completed studies on Alberta's electrical industry. After 1984, the Agency no longer intervened in PUB proceedings and all electricity policy issues, including changes to EEM legislation, were handled by the Department of Energy. Another factor contributing to lower costs was that the Agency's main function of determining generation and transmission pooled costs had become routine and mechanized.

It should be noted that not all of the Agency's operating costs were included in the figures cited in the Annual Reports. Those omitted included office accommodation and certain overhead costs incurred in administration. These were funded through Alberta's General Revenue Fund. However, as discussed in Section IV C, these expenses were not large.

B. EEM AGENCY PROCEDURES

The Agency's procedures for equalizing generation and transmission costs for Alberta Power, Edmonton Power and TransAlta developed over a number of years. The discussion below is divided into the years between amendments to EEM legislation and regulations: 1982 to 1984; 1985 to 1988; and 1989 to 1991.

1. 1982 to 1984

During the initial years of the EEM Program, all utility upstream costs were averaged based on total system generation and transmission costs. In essence the Agency purchased electric energy from Alberta Power, Edmonton Power and TransAlta at the "pooling interfaces",[12] averaged the total costs and then resold the energy to the same utilities at the pooling interface at the average cost. The utilities then passed the average costs defined by the EEM Program on to their customers.

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[11] Table IV-4 in Section IV displays total EEM Agency direct costs from 1982 to 1991.

[12] Pooling interfaces are defined as the terminus of 25 KV transmission lines.

In more detail: the first step in the process was the determination of the allowed actual energy and demand costs for the utilities by the PUB in order to generate the prices at which the utilities would sell their electric energy to the Agency.[13] The PUB approved prices comprised a fixed charge per month and a variable charge per kWh of energy sold.

The Agency then made its calculations which basically involved averaging the fixed and variable PUB charges on a monthly basis using the actual demand and energy quantities of the three utilities.[14]

The utilities also reported to the Agency the upstream (relating to generation and transmission) portion of their income tax rebates from the federal and provincial governments.[15] The Agency then pooled the utilities' rebates, determined the ratio of the total of these rebates to combined utility energy and demand costs to derive an average rebate ratio and used this ratio to allocate rebates on the basis of utility costs after Agency averaging. The allocated cost after accommodating the revised rebates set the resale price the Agency charged the utilities. In

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[13] The costs were after the Natural Gas Rebate. The Natural Gas Rebate Program was introduced in 1974 to shelter Alberta residents, commercial establishments and industries from the effects of significant price increases caused by markets outside the province. Rebates to electric utilities were discontinued in 1983, but continue for certain other Alberta natural gas users.

[14] Total costs equalled the energy and demand costs for each of the three utilities plus Cities Compensation demand costs. The latter related to the costs of transmission lines within the cities of Calgary, Lethbridge and Red Deer.

[15] Amendments were made to Alberta's Utilities Companies Income Tax Rebates Act to allow the Agency to average income tax rebates. Under the Rebate Program, the Federal and Provincial Governments rebated 95 percent and 100 percent, respectively, of the corporate income tax paid by privately owned utilities. The federal portion of the rebate was given to the consumers of the privately owned utilities to ensure compatibility between them and publicly owned utilities not paying income taxes. The rebate was frozen in 1990 for two years at the 1989/90 level. This freeze has now been extended to 1995/96. The provincial income tax rebate (both for upstream and downstream activities) was terminated in April of 1990.

effect, then, cash transfers were made from customers of lower cost utility(ies) to those of higher cost one(s), based on Agency calculations.[16]

Shielding payments were then given by the Government to those utilities whose costs had been increased by the wholesale averaging process.[17] The Shielding Program was introduced by the Alberta Government as of September 1, 1982. Shielding payments were to cover 100 percent of the increase in costs during the first year (to August 31, 1983), 80 percent in the second year and so on until they would be phased out by 1987. However, the Program was extended twice so that it did not cease until May 31, 1989.

2. 1985 to 1988

As mentioned above, the EEM Program was set up to average total generation and transmission costs for the three provincial utilities. This raised a concern that the differing costs of servicing individual groups of customers were not being accommodated. Therefore, although rate disparities were less than they had been, certain differences between similar customers in different areas continued. An additional concern was that utilities could benefit from or be adversely affected by forecasting errors in the EEM process. Minimal time was allowed for PUB scrutiny of utility forecasts (which spanned a full calendar year) and there was no provision for a hearing before the provincial pooled cost for the year was set. Adjustment hearings were held after the year end to reconsider utility forecasts, with actual costs resulting in substantial inter-utility transfers.

To alleviate these problems, amendments to the EEM legislation and regulations and to the PUB Act were made, effective January 1, 1985. As regards the EEM changes, three consumer groups were

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[16] Cities Compensation was confined to cities within TransAlta's service area. The compensation was deducted from TransAlta's transfer payments and awarded to the cities.

[17] On August 18, 1982, amendments were made to the Utilities and Telephones Grants Regulation to allow the Alberta Government to shield customers from increased rates due to EEM Agency averaging of costs at pooling interfaces.

introduced;[18] Agency prices for these groups were mandated as the basis for setting wholesale customer rates. The three customer classifications would allow the Agency to calculate the average upstream cost within each category with the intention of reducing rate differentials between similar customers in different service areas. The three categories were: residential (including farm); industrial; and general service.

The first PUB amendment required the PUB to declare the customer category price paid by a utility to the Agency for electricity to be that customer group's cost as set by PUB rates. The second PUB amendment gave consumers an opportunity to scrutinize a number of issues, in addition to the demand allocation methodology.

The mechanics of the average cost calculations made by the Agency remained the same except that now the averaging and transfers (and shielding by the Government) were done separately for each of the three residential, industrial and general service categories.[19]

3. 1989 to 1991

In 1988 further amendments were made to the legislation and regulations. These essentially enabled the PUB to hold public hearings to scrutinize the costs of new major facilities prior to inclusion in consumer rates through the EEM Program.

Again, these changes did not alter the mechanisms that the Agency used to calculate the average wholesale electricity price at pooling interfaces. But they could alter the PUB costs entering the EEM averaging procedure.

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[18] See Alta. Reg. 405/84.

[19] The utilities' industrial and general service categories were allocated costs based on their respective shares of energy and demand quantities. For the residential category only the energy share for each utility was applied to allocate combined residential energy and demand costs. Thus average residential costs did not distinguish between demand and energy elements. It follows that differences in residential load factors across the province were not reflected in residential charges at the pooling interfaces.

The Agency carried out the EEM Program until June 30, 1991 when its duties were transferred to the Alberta Department of Energy. The Department itself now applies the averaging procedures and any other duties of the EEM Agency.

IV. IMPACT OF THE EEM PROGRAM

This Section examines the impact of the Electric Energy Marketing (EEM) Program on the Alberta upstream part of the electric industry. Part A concerns the impact on the three utilities: Alberta Power; Edmonton Power; and TransAlta. Part B reviews electricity related Federal and Alberta Government payments and rebates over the life of the EEM Program. Part C looks at the direct and indirect costs of the Program, including induced costs to the three utilities.

A. KEY GENERATION, TRANSMISSION AND COST STATISTICS

The cost of electric energy over the past decade to the Alberta distributing utilities at the "pooling interfaces" - their wholesale cost - has been affected by four Government programs.[20] These are:

1. The Natural Gas Rebate Program (1982 - 1983);
2. The Federal and Provincial Corporate Income Tax Rebate Programs;
3. The EEM Program itself; and
4. The Shielding Program (1982 - May 1989).

The first two programs partially or wholly overlapped the EEM Program. The Shielding Program was part of the EEM Program but was introduced in separate legislation.

The overall impact of the EEM Program, the Rebate Programs, and the Shielding Program are evaluated below.

To trace the evolution of these programs, key data are compiled in a series of annual tables appearing in Appendix B (Tables B-1 to B-10, 1982 to 1991).

The accumulated data, 1983 to 1991, are shown in Table IV-1 overleaf. The format of this table is precisely the same as that of the annual tables. Note that the EEM Program was not operational for the first three-quarters of 1982.

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[20] These programs are discussed in more detail in Section III.

Table IV-1

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Total for 1983 to 1991

	Generation & Sales	Alberta Power		Edmonton Power		TransAlta		Total	
1	Electricity Generated, GWh	6,357		1,964		25,723		34,044	
2	Electricity Sales, GWh	5,314		5,383		20,138		30,835	
3	Electricity Demand, MW	762		880		2,859		4,502	
4	Load Factor (%)	79.6		69.8		80.4		78.2	
	Basic G & T Data at Pooling Interface	($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)
5	Actual Cost	2525.8	5.28	1615.9	3.34	6490.8	3.58	10632.5	3.83
6	Natural Gas Rebate	-0.3	0.00	-0.6	0.00	-0.7	0.00	-1.6	0.00
7	Income Tax Rebate	-355.6	-0.74	-73.7	-0.15	-1151.8	-0.64	-1581.1	-0.57
8	Cost After Rebates	2169.9	4.54	1541.6	3.18	5338.3	2.95	9049.8	3.26
9	EEM Agency Transfers	-603.3	-1.26	159.1	0.33	444.2	0.25	0.0	0.00
10	Cost After Transfers	1566.6	3.28	1700.7	3.51	5782.5	3.19	9049.8	3.26
11	Government Shielding	0.0	0.00	-65.2	-0.13	-168.5	-0.09	-233.7	-0.08
12	Cost After Transfers & Shielding	1566.6	3.28	1635.5	3.38	5614.0	3.10	8816.1	3.18
	Residential Sales & Costs at Pooling Interface*								
13	Electricity Sales, GWh	1,113		1,347		4,409		6,869	
14	Cost After Rebates	431.7	5.54	317.1	3.36	1139.1	3.69	1887.9	3.93
15	Costs After EEM Agency Transf	306.1	3.93	370.2	3.93	1211.6	3.93	1887.9	3.93
16	Cost After Transfers & Shielding	306.1	3.93	350.5	3.72	1192.5	3.86	1849.0	3.85
	General Service Sales & Costs at Pooling Interface								
17	Electricity Sales, GWh	2,491		3,575		8,996		15,063	
18	Cost After Rebates	771.5	4.42	766.7	3.06	1852.3	2.94	3390.6	3.22
19	Costs After EEM Agency Transf	546.0	3.13	857.2	3.42	1987.4	3.16	3390.6	3.22
20	Cost After Transfers & Shielding	546.0	3.13	826.0	3.30	1955.2	3.10	3327.2	3.16
	Large Industrial Sales & Costs at Pooling Interface								
21	Electricity Sales, GWh	2,204		635		7,878		10,716	
22	Cost After Rebates	625.9	4.06	108.2	2.43	1384.5	2.51	2118.5	2.82
23	Costs After EEM Agency Transf	477.0	3.09	124.7	2.81	1516.9	2.75	2118.5	2.82
24	Cost After Transfers & Shielding	477.0	3.09	119.2	2.68	1490.5	2.70	2086.6	2.78

* Totals by Consumer Group represent only the years 1985 to 1991.

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Appendix B, Tables B-2 to B-10

The data in the Tables were mainly collected by Department of Energy staff, to whom we are greatly indebted. We also thank the utilities for assistance in reviewing the information.

Table IV-1 (and the Appendix B tables) consist of five Panels with information for each of the three utilities: Alberta Power, Edmonton Power and TransAlta.

The first Panel (lines 1 through 4) deals with the basic utility system parameters of generation, sales, peak demand and average load factor.

The second Panel (lines 5 through 12) concerns generation and transmission (G&T) aggregate data at the pooling interface where the EEM transactions take place. The data include the interface cost of sales, the amount of the natural gas price and income tax rebates, EEM Program transfers and shielding payments. The final entry shows the cost of electricity at the pooling interfaces after accounting for all rebates, EEM averaging and government shielding payments.

After 1984, the EEM Program was applied separately to the three main electricity consumer groups as defined by the EEM Act - residential, general service and large industrial. The next three Panels (lines 13 through 24) summarize relevant data for each of these sectors.

All of the cost and related data in the tables are shown in millions of dollars and cents per kWh. The latter were derived using electricity sales.

Note that the 'provincial totals' referred to in the discussion below are not in fact for the province as a whole: they represent the sum for the three utilities. Medicine Hat data are excluded as this city chose not to participate in the EEM Program.

Our discussion of the impacts of the EEM and other Government Programs proceeds by line item on the tables. Summary data in the text focus on the results for the first full year of the Program (1983), the current year (1991 forecast), plus an intermediate year (1987). The summary data are pulled from the annual Tables appearing in Appendix B.

Line 1: Electricity Generation

Electricity generation is defined as:

Total electric energy generated by the utilities' plants after station service and prior to any inter-utility transactions, transmission losses or the utilities' own use.

Generation data for 1983, 1987 and 1991 and the average for the period are listed below.

	1983	1987	1991	Average 1983 to 1991
		GWh		GWh
Alberta Power	5,176	6,390	8,174	6,357
Edmonton Power	1,130	482	4,971	1,964
TransAlta	19,541	26,283	29,341	25,723
Total	25,847	33,155	42,486	34,044

TransAlta generated the majority of Province's electricity, accounting on average for 75 percent. In the mid 1980s, Edmonton Power's output was substantially reduced, reflecting "economic dispatch": the policy of using least variable cost generation on a province wide basis. Edmonton Power purchased supply from TransAlta's lower cost coal fired plants rather than using its own gas fired facilities.

Line 2: Electricity Sales

Electricity sales are defined as:

Total electric energy supplied at the 25 kV (pooling) interfaces after inter-utility transactions, transmission losses and the utilities' own use, and before any distribution losses.

Data for 1983, 1987 and 1991 and the average over this period were:

	1983	1987	1991	Average 1983 to 1991
		GWh		GWh
Alberta Power	3,532	5,166	7,534	5,314
Edmonton Power	4,860	5,313	6,043	5,383
TransAlta	15,945	19,675	25,097	20,138
Total	24,337	30,154	38,674	30,835

TransAlta was the largest seller of electricity to end-use customers in the province with around 65 percent of total sales over the period. Although on average the other two utilities each had about 17.5 percent of sales over the period, they tended to trade shares between 1983 and 1991: in 1983 Alberta Power had 14.5 percent of sales and Edmonton Power 20 percent; in 1991 the respective percentages were 19.5 and 15.6 percent.

Total utility sales grew at an average annual rate of 5.8 percent from 1983 to 1991. The largest increase (9.5 percent per year) was experienced by Alberta Power and the lowest by Edmonton Power (2.7 percent per year).

Line 3: Peak Electricity Demand

Line 3 presents electricity peak demand, defined as:

> Weighted[21] peak[22] hourly demand supplied at the 25 kV (pooling) interface net of the weighted interruptible load, transmission losses and utilities' own use, and prior to any distribution losses.

Summary data are shown below.

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[21] In this definition of peak demand, the term 'weighted' means: 1983 to 1986 = 100 percent of annual winter peak; 1987 = 75 percent of annual winter peak and 25 percent of average monthly peak; 1988 to 1991 = 50 percent for the 3 winter months and 50 percent for the rest of the year.

[22] Note that the peaks relate to sales at the interface by utility, not generating peaks.

	1983	1987	1991	Average 1983 to 1991
		MW		MW
Alberta Power	543	746	997	762
Edmonton Power	838	815	978	880
TransAlta	2,433	2,666	3,209	2,859
Total	3,814	4,227	5,184	4,501

As would be expected given its share of the market, TransAlta's peak demand is much higher than that for the other two utilities.

Line 4: Load Factor

This line gives the load factor (annual electricity sales as a percent of electricity peak demand, assuming the latter were continuous over the year) for each utility.

	1983	1987	1991	Average 1983 to 1991
		%		%
Alberta Power	74.2	79.1	86.2	79.6
Edmonton Power	66.2	74.5	69.2	69.6
TransAlta	74.8	84.2	89.3	80.4
Total	72.8	81.4	84.8	78.2

The provincial load factor apparently has increased noticeably over the period. However, these data might have been affected by changes in the definition of peak demand.

Line 5: Cost of Sales at Pooling Interface

This line shows the cost of electricity sales (the sum of energy and demand charges) for the three utilities and their averages. The unit costs have varied as follows:

	1983	1987 ¢/kWh	1991	Average 1983 to 1991 ¢/kWh
Alberta Power	5.72	5.46	5.18	5.28
Edmonton Power	4.14	2.50	4.95	3.34
TransAlta	3.30	3.97	3.33	3.58
Total	3.82	3.97	3.94	3.83

In 1983, 1987 and 1991, Alberta Power's actual costs (before rebates, transfers or shielding) were about 1.5, 1.4 and 1.3 times the provincial average. The respective ratios for Edmonton Power were 1.1, 0.63 and 1.3; for TransAlta they were 0.9, 1.0 and 0.9. From 1985 to 1990 Edmonton Power's average costs were less than TransAlta's. This reflected in part low cost purchases from TransAlta, and relief from income tax (recall that these costs are before income tax rebates).

Line 6: Natural Gas Price Rebate

The Natural Gas Price Rebate Program of the Alberta Government was designed to offset the impact of rising prices of natural gas (for more details see Section III). In the context of electricity, the price rebates applied to natural gas used for energy generation. The rebates were discontinued at the end of 1983. When applicable, they were relatively modest, totalling $200,000 for the last quarter of 1982 (split equally between Alberta Power and TransAlta) and $1.6 million in 1983, $300 thousand to Alberta Power, $600 thousand to Edmonton Power, and $700 thousand to TransAlta. The value of total rebates in 1982 and 1983 expressed in terms of units of total power generated were 0.0008 ¢/kWh and 0.006 ¢/kWh respectively.

Line 7: Income Tax Rebate

Corporate income tax rebates related to generation and transmission are shown below. Recall the main purpose of the rebates was to provide for consistent treatment between private and publicly owned utilities. Provincial income tax rebates were discontinued in 1990 and the federal portion has been frozen at its 1989/90 level until 1995/96 (see Section III). Note that the rebates shown are before EEM averaging.

	1983	1987	1991	Average 1983 to 1991
		¢/kWh		¢/kWh
Alberta Power	(0.79)	(0.83)	(0.42)	(0.74)
Edmonton Power[23]	(0.28)	(0.13)	(0.05)	(0.15)
TransAlta	(0.46)	(0.80)	(0.42)	(0.64)
Total	(0.47)	(0.69)	(0.36)	(0.57)

The rebates represented a sizeable credit for customers of the two privately owned utilities, Alberta Power and TransAlta, especially before elimination of the provincial rebates.

Line 8: Cost After Rebates

The pattern of the costs at the pooling interface after rebates is summarized below.

	1983	1987	1991	Average 1983 to 1991
		¢/kWh		¢/kWh
Alberta Power	4.91	4.63	4.76	4.54
Edmonton Power	3.85	2.37	4.91	3.18
TransAlta	2.84	3.17	2.91	2.95
Total	3.35	3.28	3.58	3.26

The costs are those that would have been incurred in the absence of transfers under the EEM Program or shielding

Alberta Power's costs were 1.5, 1.4 and 1.3 times the total average in 1983, 1987 and 1991, respectively. The respective values for Edmonton Power were 1.2, 0.7 and 1.4 and for TransAlta were 0.9, 1.0 and 0.8. The figures for 1983 illustrate the situation which had led to the EEM Program, namely the significant spread in wholesale costs between Alberta Power and Edmonton Power, and those for TransAlta.

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[23] Edmonton Power as a publicly owned utility did not pay income tax. The entries here represent rebates on power it purchased from privately owned utilities on which income tax had been levied.

Line 9: EEM Program Transfers

Transfers under the EEM Program (before shielding) over the period 1983 to 1991 were:

	1983	1987 ¢/kWh	1991	Average 1983 to 1991 ¢/kWh
Alberta Power	(1.60)	(1.24)	(1.18)	(1.26)
Edmonton Power	(0.26)	1.05	(0.89)	0.33
TransAlta	0.43	0.04	0.57	0.25
Total	0	0	0	0

Recall that the EEM transfers were meant to smooth generation and transmission costs (after the natural gas price and income tax rebates). Alberta Power and Edmonton Power were recipients of transfers in 1983 and 1991. However, for the period as a whole, Edmonton Power was a net contributor, along with TransAlta. The amounts shown as additional costs imposed on TransAlta under the EEM Program are net of transmission line compensation for the cities of Calgary, Lethbridge and Red Deer. Thus TransAlta's transfers before this compensation are higher by the amount of it.

The sum of total net transfers for the three utilities for any year is zero.

Line 10: Cost After EEM Program Transfers

The variation in the unit electricity costs after EEM Program transfers but before any shielding over the period is summarized below.

	1983	1987 ¢/kWh	1991	Average 1983 to 1991 ¢/kWh
Alberta Power	3.31	3.39	3.57	3.28
Edmonton Power	3.60	3.41	4.02	3.51
TransAlta	3.28	3.21	3.48	3.19
Total	3.35	3.28	3.58	3.26

As discussed in Section III, EEM Program transfers were calculated and administered to equalize the energy and the demand

components of total G&T costs until 1985, after which the averaging was done separately for the residential (including farm), general service and industrial consumer groups.

The fact that the costs after EEM Program transfers are not identical among the three utilities is due to load factor differences in the general service and large industrial classes.[24] In each of these classes, the respective unit energy costs in cents/kWh and the respective demand charges in dollars/kW are the same.

Line 11: Government Shielding

As discussed in Section III, when the EEM Program was introduced the Alberta Government also instituted shielding payments to compensate the customers of utilities whose costs would rise because of averaging. The Program extended over the period September 1, 1982 to May 31, 1989. The impact of shielding is summarized below. Note that the years highlighted below differ from the other entries, given the year in which shielding was terminated.

	(4 months) 1982	1986 ¢/kWh	(5 months) 1989	Average[25] 1982 to 1989 ¢/kWh
Alberta Power	0	0	0	0
Edmonton Power	0	(0.36)	(0.18)	(0.19)
TransAlta	(0.68)	(0.09)	(0.07)	(0.16)
Total	(0.44)	(0.12)	(0.08)	(0.14)

Alberta Power always received credits under the EEM Program and thus did not qualify for shielding grants. Edmonton Power received about 0.19 ¢/kWh on average from 1982 to 1989 and TransAlta, 0.16 ¢/kWh. The credits fell over time as the shielding

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[24] Costs after transfers are the same for the residential sector, where any load factor differences are subsumed in the averaging process.

[25] Note that the overall averages as calculated include sales for Alberta Power. The sales used to derive 1982 and 1989 unit costs reflect the number of months in those years that the Program was in place.

payments were progressively reduced.

Line 12: Cost After Transfers & Shielding

This line gives the final overall "wholesale cost" at the pooling interface after all rebates, EEM transfers and shielding. The results by selected year are:

	1983	1987	1991	Average 1983 to 1991
		¢/kWh		¢/kWh
Alberta Power	3.31	3.39	3.57	3.28
Edmonton Power	3.60	3.07	4.02	3.38
TransAlta	2.87	3.14	3.48	3.10
Total	3.08	3.17	3.58	3.18

In 1983 the ratios of Alberta Power's, Edmonton Power's and TransAlta's adjusted costs to the provincial average for the year were 1.1, 1.2 and 0.9, respectively. In 1991 the ratios were 1.0, 1.1 and 1.0, respectively. The spread between the average costs for each utility over the entire period and the combined total is relatively small. This provides a broad measure of the overall effectiveness of the EEM Program.

After 1984, the EEM pooling calculations were applied separately to three customer categories: residential; general service; and large industrial. Therefore the tables for 1985 to 1991 (Tables B-4 to B-10 in Appendix B) contain data in the last three panels (Lines 13 to 24) relating to each category. These line items are discussed next.

The summary data for each Line in the following text are for 1985, 1988 and 1991, plus the average for the years 1985 to 1991 inclusive.

We emphasize the cost data discussed below by consumer category are at the pooling interfaces (wholesale costs) and not at the point of final consumption (retail costs).

Line 13: Residential Sales at the Pooling Interface

The General Regulations under the EEM Act define residential consumers as,

"...all those who consume electric energy at a residence or on a farm for domestic or farm purposes and who are billed directly by an owner, a municipality or a rural electrification association." (EEM Act, p.1)

The share of residential sales (including farm) for the three utilities, are:

	1985	1988 %	1991	Average 1985 to 1991 %
Alberta Power	16.4	16.1	15.9	16.2
Edmonton Power	19.6	19.5	19.6	19.6
TransAlta	64.0	64.4	64.5	64.2
Total	100.0	100.0	100.0	100.0

The residential market shares between the utilities have been remarkably stable.

Line 14: Residential Costs After Rebates

The costs of sales after the Natural Gas Price and Income Tax Rebates are those that would have been borne by each utility in the absence of the EEM Program and shielding. The costs in 1985, 1988 and 1991 and average costs over this period are:

	1985	1988 ¢/kWh	1991	Average 1985 to 1991 ¢/kWh
Alberta Power	5.07	5.42	5.84	5.54
Edmonton Power	3.82	2.30	5.40	3.36
TransAlta	4.31	2.77	3.66	3.69
Total	4.34	3.10	4.35	3.93

The lowest unit costs for residential customers (after rebates) was experienced by Edmonton Power in 1985 and 1988, and by TransAlta Utilities in 1991. On average over the period Edmonton Power customers had the lowest costs before the EEM and shielding Programs. The significant difference between the Edmonton Power and the Alberta Power costs compared with TransAlta's in 1991 should be noted. Recall that Edmonton Power's Genesee II generating plant entered the utility's rate base in 1990.

Line 15: Residential Costs After EEM Agency Transfers

The unit costs after rebates and EEM Program transfers but before shielding for 1985, 1988 and 1991 and average costs are:

	1985	1988 ¢/kWh	1991	Average 1985 to 1991 ¢/kWh
Alberta Power	4.34	3.10	4.35	3.93
Edmonton Power	4.34	3.10	4.35	3.93
TransAlta	4.34	3.10	4.35	3.93
Total	4.34	3.10	4.35	3.93

The costs after EEM averaging for each utility's residential sales were identical. This is because, unlike the general service and industrial customer categories, in the EEM averaging calculations demand and energy costs were added together and divided by residential sales. Therefore load factor variations would not affect unit costs.

Although unit costs were almost the same in 1991 as in 1985, significant decreases were experienced between these two years.

Line 16: Residential Costs After Transfers & Shielding

Shielding remained in effect to 1989. From 1990 on, the figures in Line 16 are identical with those of Line 14. Costs after shielding in 1985, 1988 and 1991 and the average over this period are shown below.

	1985	1988 ¢/kWh	1991	Average 1985 to 1991 ¢/kWh
Alberta Power	4.34	3.10	4.35	3.93
Edmonton Power	4.03	2.94	4.35	3.72
TransAlta	4.19	3.00	4.35	3.86
Total	4.18	3.01	4.35	3.85

After shielding and transfers, Edmonton Power had the lowest residential costs of the three utilities in 1985 and 1988 and on average. In 1991 there was no shielding so Line 16 costs were the same for all the utilities. Alberta Power did not qualify for

shielding. Therefore its costs are the same as before shielding and are the highest of the three utilities. TransAlta's costs are close to the average for the combined utilities, partly a reflection of their weight (about two thirds, see beforehand) in the total.

Line 17: General Service Sales at the Pooling Interface

The Regulations under the EEM Act define General Service customers as,

> "...all those who consume electric energy who are not part of the residential consumer group or the large industrial consumer group and includes those who consume electric energy in irrigation work..." (EEM Act, p.1)

The General Service electricity sales for each utility as a percentage of total sales for this category are shown below.

	1985	1988	1991	Average 1985 to 1991
		%		%
Alberta Power	15.3	17.0	17.0	16.5
Edmonton Power	24.6	23.5	22.9	23.7
TransAlta	60.1	59.5	60.1	59.8
Total	100.0	100.0	100.0	100.0

TransAlta had approximately 60 percent of total General Service sales over the period. The shares among utilities are quite stable.

Line 18: General Service Costs After Rebates

The costs after the Natural Gas and Income Tax Rebates are those that would have applied in the absence of the EEM Program and shielding. The unit costs for selected years and on average are:

	1985	1988 ¢/kWh	1991	Average 1985 to 1991 ¢/kWh
Alberta Power	3.60	4.41	4.84	4.42
Edmonton Power	3.22	2.25	4.95	3.06
TransAlta	2.70	2.96	2.92	2.94
Total	2.97	3.04	3.71	3.22

In the absence of the EEM Program, TransAlta would have had the lowest General Service unit costs in 1985, 1991 and on average over the period. Alberta Power would have had the highest. Edmonton Power's costs from 1986 to 1989 fell below TransAlta's because of falling gas prices, the inclusion of new generation facilities in TransAlta's rate base and the purchase of low cost power from TransAlta.

Line 19: General Service Costs After EEM Agency Transfers

Unit costs after EEM transfers but before shielding are summarized below.

	1985	1988 ¢/kWh	1991	Average 1985 to 1991 ¢/kWh
Alberta Power	2.94	2.88	3.59	3.13
Edmonton Power	3.25	3.20	4.06	3.42
TransAlta	2.86	3.03	3.61	3.16
Total	2.97	3.04	3.71	3.22

Unlike the residential sector, demand and energy costs are segregated in the General Service category. Therefore, when combined energy and demand costs for each utility are expressed as a function of electricity sales, cost differences occur by virtue of load factor variations.

Alberta Power had the lowest unit costs on average over the period 1985 to 1991; TransAlta's are only marginally higher. Edmonton Power had considerably higher unit costs, given its relatively low load factors.

We caution that while the above comparisons are correct in an aggregate sense they need to be qualified because of significant

differences in load factor in the General Service category among the three utilities.

Line 20: General Service Costs After Transfers & Shielding

Costs after all rebates, transfers and shielding at the pooling interface for 1985, 1988 and 1989 and the average for the period are:

	1985	1988	1991	Average 1985 to 1991
		¢/kWh		¢/kWh
Alberta Power	2.94	2.88	3.59	3.13
Edmonton Power	3.23	3.01	4.06	3.30
TransAlta	2.67	2.98	3.61	3.10
Total	2.85	2.97	3.71	3.16

After shielding, TransAlta had the lowest average costs from 1985 to 1991, followed by Alberta Power. Edmonton Power's average costs for the period were some 0.20 ¢/kWh higher than TransAlta's costs and 0.17 ¢/kWh more the Alberta Power's costs, reflecting load factors.

Line 21: Large Industrial Sales at the Pooling Interface

The General Regulation under the EEM Act defines Large Industrial customers as those

> "i) whose forecast maximum demand for electric energy is equal to or greater than 2000 kilowatts per service, and ii) who process a feed stock, produce a primary product, manufacture a product or transport a product to market." (EEM Act, p.1)

Each utility's share of total industrial sales is as follows.

	1985	1988	1991	Average 1985 to 1991
		%		%
Alberta Power	15.2	20.7	24.3	20.6
Edmonton Power	7.0	5.8	4.9	5.9
TransAlta	77.8	73.5	70.8	73.5
Total	100.0	100.0	100.0	100.0

Alberta Power's share rose notably over the period, while Edmonton Power's and TransAlta's fell. The latter utility had the major proportion of industrial sales. Note Edmonton Power's small and declining proportion of total Industrial sales.

Line 22: Large Industrial Costs After Rebates

The costs after income tax rebates are those that would have been borne by each utility in the absence of the EEM Program and shielding. Costs in 1985, 1988 and 1991 and the average during this period are:

	1985	1988	1991	Average 1985 to 1991
		¢/kWh		¢/kWh
Alberta Power	3.92	4.08	4.31	4.06
Edmonton Power	2.43	1.87	3.61	2.43
TransAlta	2.37	2.36	2.54	2.51
Total	2.46	2.68	3.02	2.82

TransAlta's costs after rebates would have been relatively constant in the range of 2.36 to 2.54 ¢ per kWh. In 1988, Edmonton Power's costs were below TransAlta's (partly by virtue of purchases of low cost power from TransAlta), but rose sharply at the end of the period. On average over the period Alberta Power's Industrial costs before rebates were much higher than the other two utilities.

Line 23: Industrial Costs After EEM Agency Transfers

The costs after EEM transfers (but before shielding) for 1985, 1988 and 1991 and the average for this period are:

	1985	1988 ¢/kWh	1991	Average 1985 to 1991 ¢/kWh
Alberta Power	2.47	2.92	3.29	3.09
Edmonton Power	2.52	2.67	3.05	2.81
TransAlta	2.45	2.62	2.93	2.75
Total	2.46	2.68	3.02	2.82

As with General Service, the demand component causes costs per unit of energy after EEM averaging to vary among the utilities by virtue of differences in load factor. All the utilities' unit costs increased over time.

Line 24: Large Industrial Costs After Transfers & Shielding

The costs after EEM transfers and shielding between 1985 and 1991 and the average for the period are as follows. Recall that shielding terminated in 1989.

	1985	1988 ¢/kWh	1991	Average 1985 to 1991 ¢/kWh
Alberta Power	2.47	2.92	3.29	3.09
Edmonton Power	2.46	2.51	3.05	2.68
TransAlta	2.35	2.55	2.93	2.70
Total	2.38	2.62	3.02	2.78

TransAlta had the lowest unit costs in 1985, and in 1991, but higher costs than Edmonton Power in 1988. Alberta Power's costs exceeded those of the other utilities over the entire period, by virtue of lower load factors. Again the unit costs of each of the utilities increased over the period.

The spread in costs after transfers and shielding in the Large Industrial sector is more noticeable than for the General Service category, reflecting stronger differences in underlying load factors.

Overall Comments

The extensive data shown in Tables B-1 to B-10 in Appendix B and Table IV-1 are summarized in Tables IV-2 to IV-4. We confine

these Tables to the aggregate of the three customer categories (Residential, General Service and Industrial). Selected data are also provided in graphical form in Figures IV-1 through IV-5.

The crucial comparisons are those between the G&T costs which would have prevailed without the EEM Program and the costs after the EEM transfers and shielding.

Accordingly, Table IV-2 brings together the time series (1982 to 1991) of unit actual costs of sales at the pooling interface (line 5), the unit costs after rebates (line 8) and the unit costs after transfers and shielding (line 12), for each utility and on a combined basis.

Before we look at the comparisons, it is worthwhile noting that the average actual costs for the combined utilities showed only modest variations over the period, with (forecast) costs in 1991 much the same as actual costs in 1983. The costs are in nominal terms, so the real average cost of sales - the cost after adjustment for inflation - has fallen. This aggregate trend masks some differences for individual utilities, with Edmonton Power displaying a distinctive 'U' shape, while TransAlta showed an inverted 'U' or humped profile. These patterns are influenced by the timing of rate-base additions by the utilities.

The differences in unit costs are shown in absolute terms in Table IV-3 and in ratio form in Table IV-4.

In the case of **Alberta Power**, the numbers indicate the substantial magnitude of the EEM adjustments. Alberta Power customers were recipients of EEM Program relief in every year. The ratio of costs after the EEM transfers and shielding to actual costs after rebates is quite stable over time. The average ratio, 1983 to 1991,[26] of 0.73 and the ratios in the last two years offer a rough rule of thumb: Alberta Power's costs after the EEM Program are currently about three quarters of costs after rebates.

Edmonton Power was initially an EEM Program recipient, but then became a noticeable contributor until the commissioning of the Genesee Plant II, which made Edmonton Power a program beneficiary

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[26] 1983 is preferred to 1982 because the program was only in effect for four months of that year.

Table IV-2

Aggregate Electricity Costs at the Pooling Interfaces, Three Utilities, 1982 - 1991
Cents/kWh

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1983-1991 Average
Alberta Power											
Actual Cost (line 5)	5.21	5.72	5.63	4.63	4.97	5.46	5.29	5.39	5.37	5.18	4.76
Cost after Rebates (line 8)	4.67	4.91	4.60	3.77	4.20	4.63	4.47	4.56	4.77	4.76	4.07
Cost After Transfers and Shielding (line 12)	4.08	3.31	3.32	3.15	3.41	3.39	2.94	2.99	3.37	3.57	2.95
Edmonton Power											
Actual Cost (line 5)	4.12	4.14	3.77	3.54	2.94	2.50	2.35	2.31	3.54	4.95	3.00
Cost after Rebates (line 8)	3.92	3.85	3.47	3.28	2.71	2.37	2.22	2.25	3.51	4.91	2.86
Cost After Transfers and Shielding (line 12)	3.63	3.60	3.52	3.34	3.03	3.07	2.94	3.05	3.77	4.02	3.03
TransAlta											
Actual Cost (line 5)	2.43	3.30	3.73	3.64	3.94	3.97	3.59	3.47	3.37	3.33	3.23
Cost after Rebates (line 8)	2.18	2.84	3.12	2.95	3.12	3.17	2.70	2.68	3.08	2.91	2.66
Cost After Transfers and Shielding (line 12)	2.17	2.87	3.18	2.91	3.05	3.14	2.82	2.88	3.41	3.48	2.77
Combined Utilities											
Actual Cost (line 5)	3.18	3.82	4.02	3.78	3.93	3.97	3.69	3.63	3.76	3.94	3.45
Cost after Rebates (line 8)	2.90	3.35	3.40	3.14	3.22	3.28	2.94	2.96	3.46	3.58	2.93
Cost After Transfers and Shielding (line 12)	2.75	3.08	3.26	3.02	3.10	3.17	2.86	2.93	3.46	3.58	2.85

Note: The average cost excludes the value for 1982 since the EEM Program was only operating in the last 4 months of that year.

Source: Appendix B, Tables B-1 to B-10

Table IV-3

Aggregate Electricity Cost Differentials at the Pooling Interfaces, Three Utilities, 1982 - 1991

Cents/kWh

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1983-91 Ave.
Alberta Power											
Cost after Transfers & Shielding less Actual Cost (line 12 - line 5)	-1.13	-2.41	-2.31	-1.48	-1.56	-2.07	-2.35	-2.40	-2.00	-1.61	-1.82
Cost after Transfers & Shielding less Cost after Rebates (line 12 - line 8)	-0.59	-1.60	-1.28	-0.62	-0.79	-1.24	-1.53	-1.57	-1.40	-1.19	-1.12
Edmonton Power											
Cost after Transfers & Shielding less Actual Cost (line 12 - line 5)	-0.49	-0.54	-0.25	-0.20	0.09	0.57	0.59	0.74	0.23	-0.93	0.03
Cost after Transfers & Shielding less Cost after Rebates (line 12 - line 8)	-0.29	-0.25	0.05	0.06	0.32	0.70	0.72	0.80	0.26	-0.89	0.18
TransAlta											
Cost after Transfers & Shielding less Actual Cost (line 12 - line 5)	-0.26	-0.43	-0.55	-0.73	-0.89	-0.83	-0.77	-0.59	0.04	0.15	-0.46
Cost after Transfers & Shielding less Cost after Rebates (line 12 - line 8)	-0.01	0.03	0.06	-0.04	-0.07	-0.03	0.12	0.20	0.33	0.57	0.12
Combined Utilities											
Cost after Transfers & Shielding less Actual Cost (line 12 - line 5)	-0.43	-0.74	-0.76	-0.76	-0.83	-0.80	-0.83	-0.70	-0.30	-0.36	-0.61
Cost after Transfers & Shielding less Cost after Rebates (line 12 - line 8)	-0.15	-0.27	-0.14	-0.12	-0.12	-0.11	-0.08	-0.03	0.00	0.00	-0.09

Note: The average differential excludes the value for 1982 since the EEM Program was only operating in the last 4 months of that year.

Source: Table IV-2

Table IV-4

Ratio of Electricity Costs at the Pooling Interfaces, Three Utilities, 1982 - 1991

Cents/kWh

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1983-1991 Average
Alberta Power											
Cost after Transfers & Shielding / Actual Cost (line 12 / line 5)	0.78	0.58	0.59	0.68	0.69	0.62	0.56	0.55	0.63	0.69	0.62
Cost after Transfers & Shielding / Cost after Rebates (line 12 / line 8)	0.87	0.67	0.72	0.84	0.81	0.73	0.66	0.66	0.71	0.75	0.72
Edmonton Power											
Cost after Transfers & Shielding / Actual Cost (line 12 / line 5)	0.88	0.87	0.93	0.94	1.03	1.23	1.25	1.32	1.06	0.81	1.01
Cost after Transfers & Shielding / Cost after Rebates (line 12 / line 8)	0.93	0.94	1.01	1.02	1.12	1.30	1.32	1.36	1.07	0.82	1.06
TransAlta											
Cost after Transfers & Shielding / Actual Cost (line 12 / line 5)	0.89	0.87	0.85	0.80	0.77	0.79	0.79	0.83	1.01	1.05	0.86
Cost after Transfers & Shielding / Cost after Rebates (line 12 / line 8)	1.00	1.01	1.02	0.99	0.98	0.99	1.04	1.07	1.11	1.20	1.04
Combined Utilities											
Cost after Transfers & Shielding / Actual Cost (line 12 / line 5)	0.86	0.81	0.81	0.80	0.79	0.80	0.78	0.81	0.92	0.91	0.82
Cost after Transfers & Shielding / Cost after Rebates (line 12 / line 8)	0.95	0.92	0.96	0.96	0.96	0.97	0.97	0.99	1.00	1.00	0.97

Note: The average ratio excludes the value for 1982 since the EEM Program was only operating in the last 4 months of that year.

Source: Table IV-2

Figure IV - 1

Aggregate Electricity Costs
- Alberta Power -

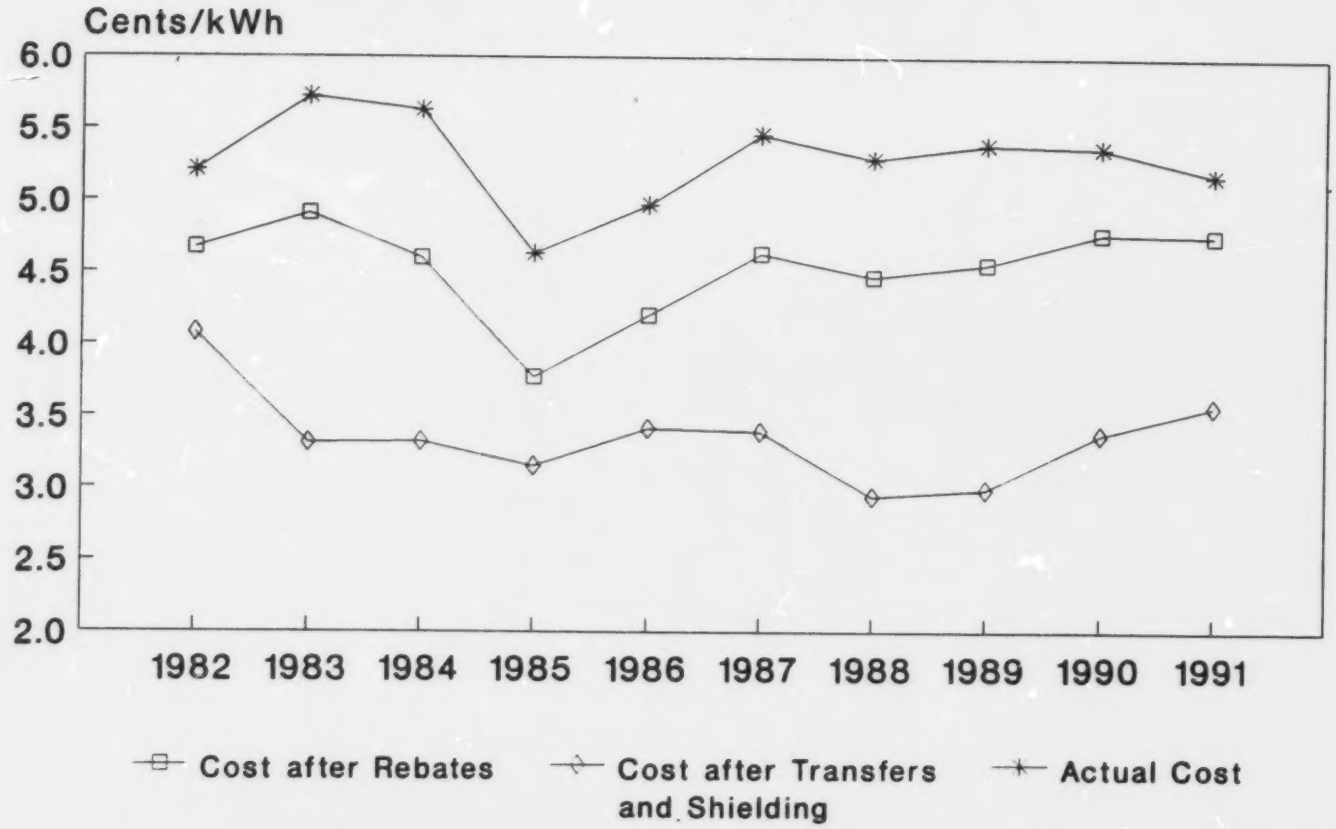


Figure IV - 2

Aggregate Electricity Costs
- Edmonton Power -

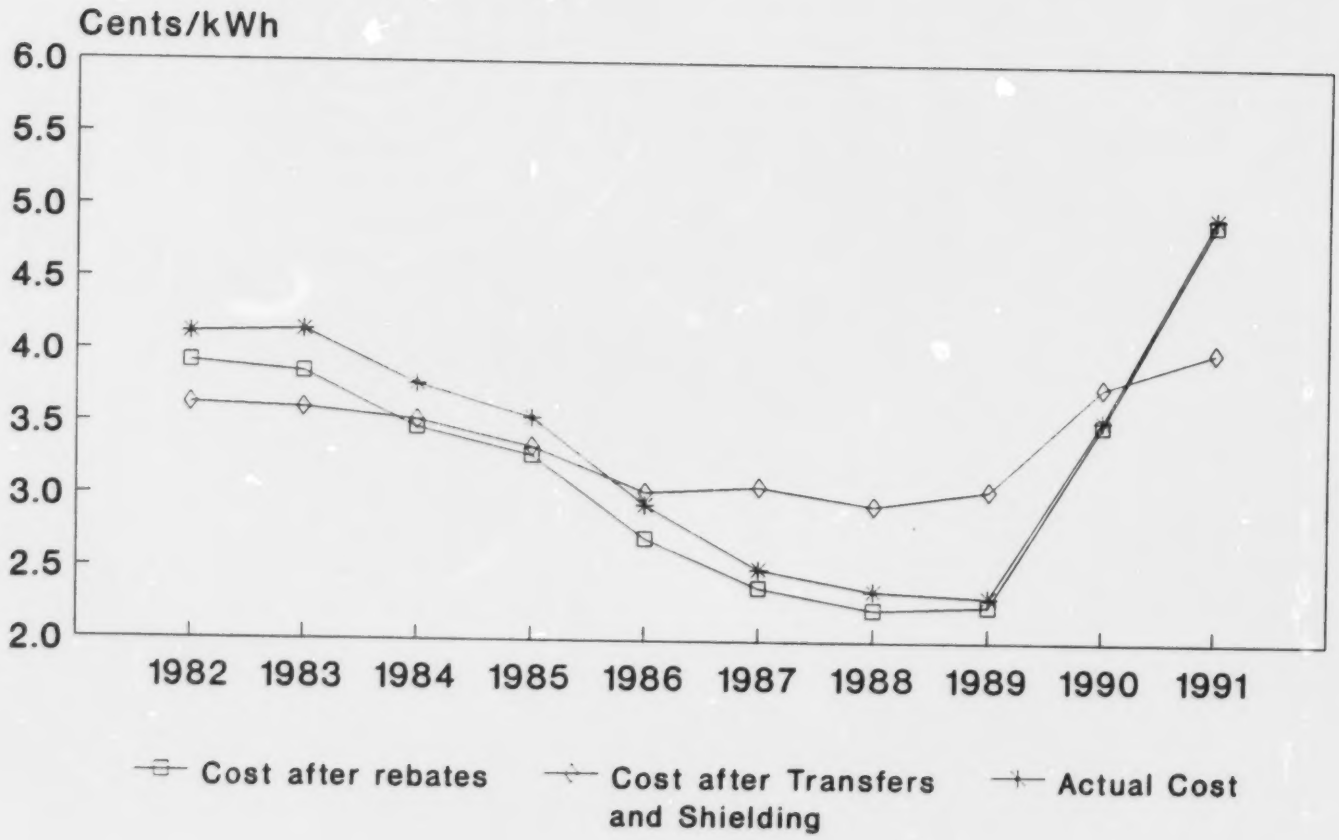


Figure IV - 3

Aggregate Electricity Costs
- TransAlta -

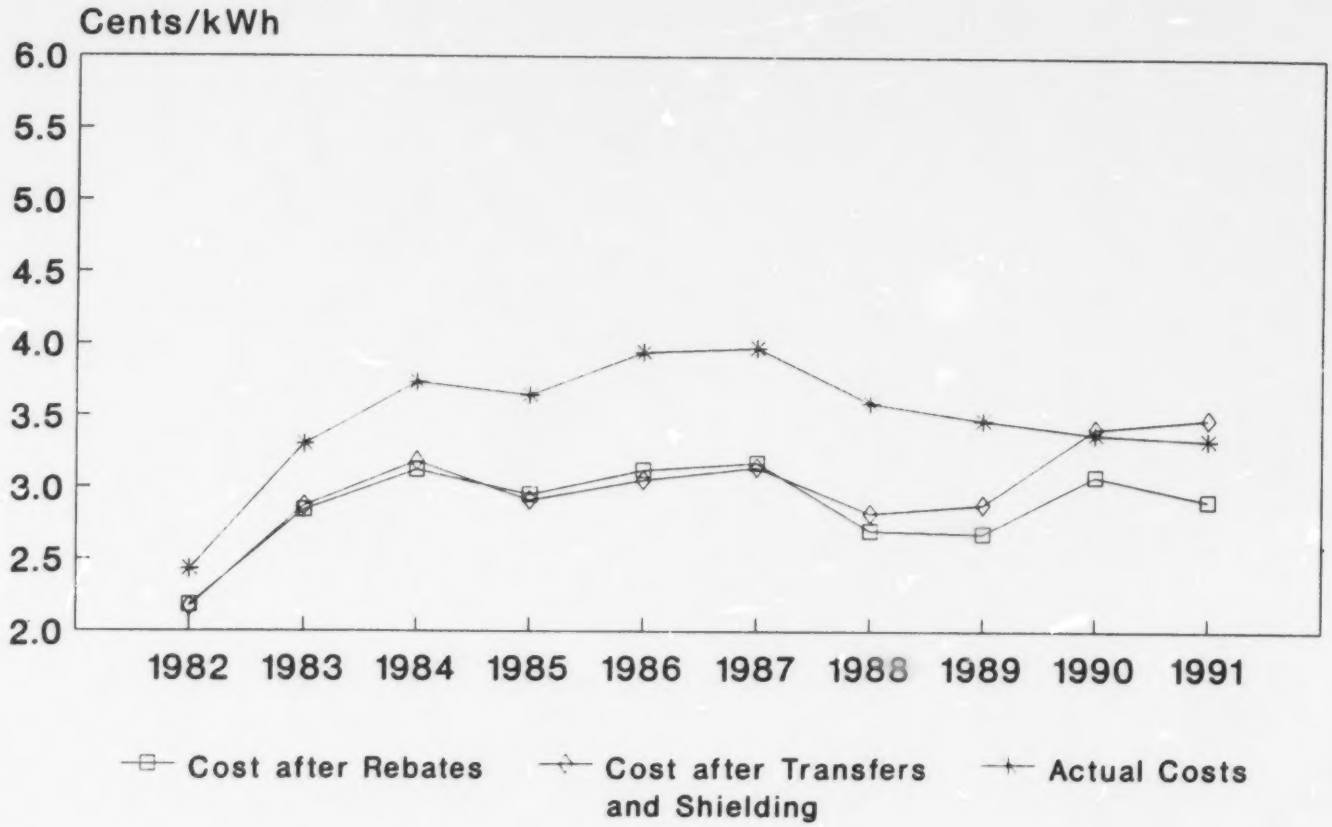
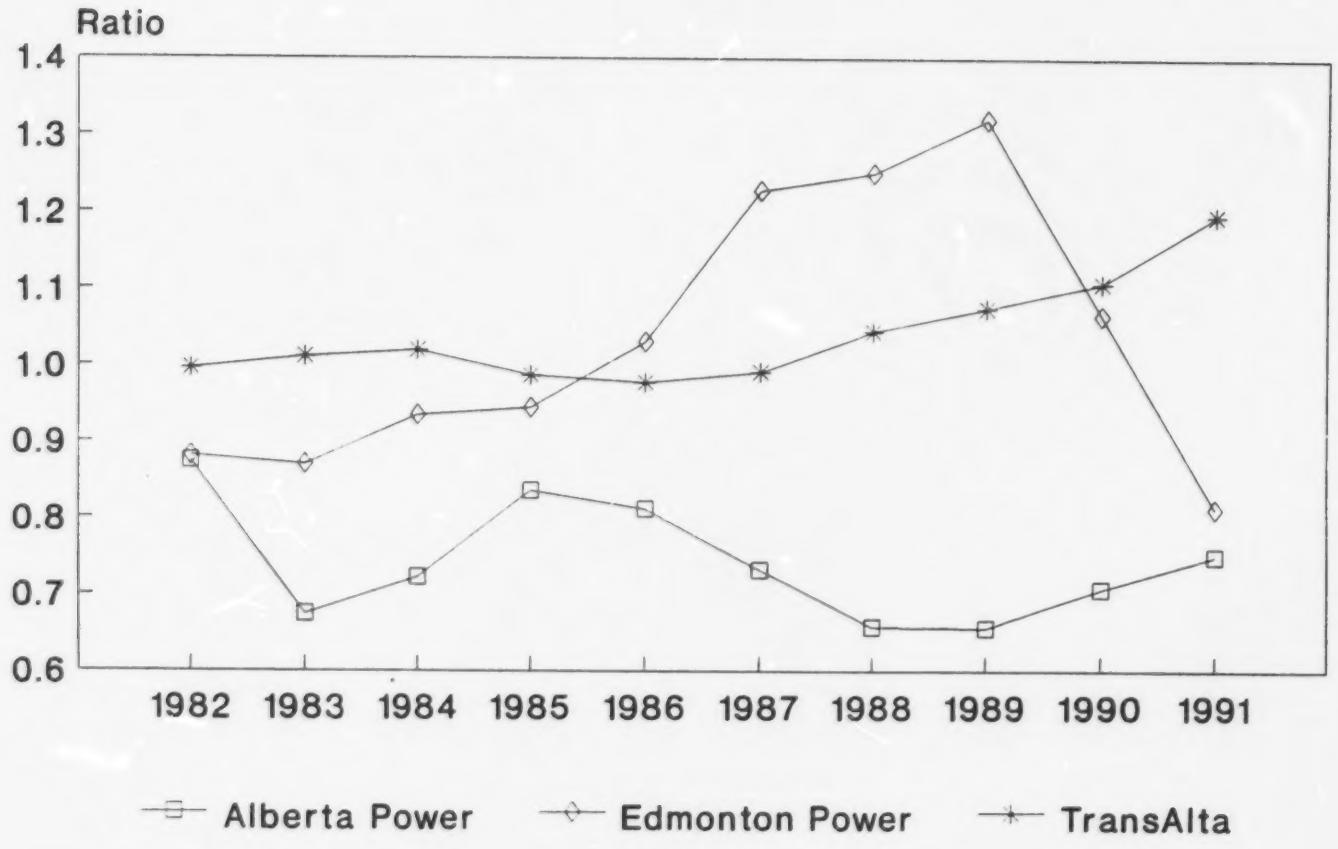


Figure IV - 4

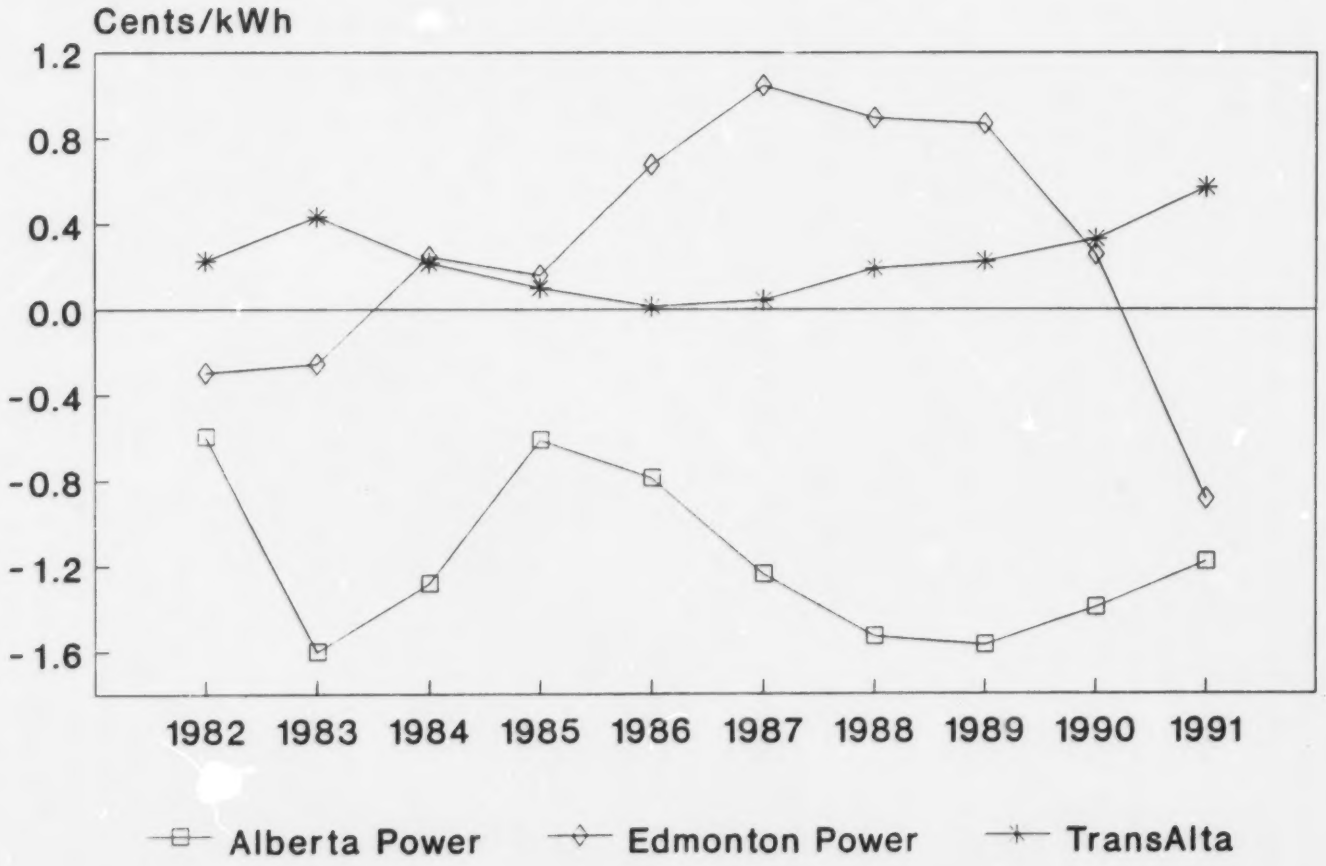
Cost Ratios*



* Cost after transfers and shielding to cost after rebates

Figure IV - 5

EEM Program Transfers after Shielding



in 1991. This history is mirrored in the ratios. Data for 1991 suggest that Edmonton Power's costs after EEM transfers are about 80 percent of its costs after rebates.

TransAlta, partly because of shielding and also because Edmonton Power became a contributor, was almost not affected by the EEM Program until after 1987. But beyond that year it has became a growing and substantial Program contributor. The (forecast) data for 1991 show costs after EEM transfers would exceed costs after rebates by about 20 per cent.

The data for the combined utilities confirm that after the elimination of shielding in 1989 aggregate costs before and after EEM transfers (and after rebates) are the same.

B. ELECTRICITY RELATED GOVERNMENT PAYMENTS AND REBATES

Government payments and rebates to the three Alberta utilities for the years 1982 to 1991 are listed in Table IV-5. Public funds disbursed and refunds include natural gas price rebates, income tax rebates and shielding benefits. Each component is discussed below.

1. Natural Gas Rebates

As discussed in Section III, the Natural Gas Rebate Program was introduced in 1974 to protect Alberta consumers from rising natural gas prices. For the period during which this program overlapped with the EEM Program (September 1982 to December 1983), natural gas price rebates amounted to $1.85 million. TransAlta received close to half of this amount, Edmonton Power about one-third and Alberta Power the remainder.

2. Income Tax Rebates

Income tax rebates are the largest component of government transfers to the two privately owned utilities. Note that unlike the rebates shown in Tables IV-1 and B-1 to B-10 which only relate to G&T operations, the figures in Table IV-5 include rebates on downstream operations.

Edmonton Power does not receive any direct tax rebates since as a municipally-owned company it is not subject to income taxes.[27] The ninety-five percent refund of federal income tax levies to the two privately owned utilities was frozen in 1990 for two years at the 1989/90 level. This freeze has now been extended to 1995/96. The rebate of 100 percent of provincial tax paid by the utilities was discontinued in February, 1990.

In total, some $1.4 billion was refunded to the two utilities by the Federal Government and $460 million by the Provincial Government.

3. Shielding Program

The Shielding Program was instituted to partially offset the increase in the cost of electricity resulting from EEM transfers from utilities with lower than average G&T costs. As discussed earlier, Alberta Power's customers received no shielding benefits since its G&T costs were the highest in the province. Thus it benefited from EEM transfers.

TransAlta was the major beneficiary of shielding since it was often the lowest-cost producer of electricity in the province and had the highest sales. It received some $200 million of revenue through shielding, three-quarters of the total funds paid out over the life of the program.

Edmonton Power received some $65 million in shielding grants during the years 1984 to 1989.

4. EEM Agency Direct Costs

The direct costs of administering the Agency are allocated equally to each utility on the premise that the amount of work done for each was approximately the same. These costs were not allocated to the utilities (as originally intended) but were paid out of Alberta's General Revenue Fund.

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[27] On power purchased from the two privately owned utilities, Edmonton Power paid full cost including income taxes. Consequently it was also entitled to receive income tax rebates from those utilities.

Government Payments and Rebates to Electric Industry
(for calender year ($000))

	Natural Gas Rebates	Income Tax Rebates Federal	Income Tax Rebates Provincial	Shielding	Agency Direct Costs	Total
Alberta Power						
1982(1)	91	4,123	4,349	0	59	8,622
1983	327	31,478	11,318	0	161	43,283
1984	0	42,848	13,901	0	142	56,891
1985	0	41,812	14,320	0	123	56,255
1986	0	40,558	11,811	0	110	52,479
1987	0	38,291	19,382	0	103	57,777
1988	0	43,879	18,091	0	106	62,076
1989	0	42,333	21,112	0	112	63,557
1990	0	40,559	5,206	0	117	45,882
1991	0	37,897	(171)	0	59	37,786
Subtotal	418	363779	119320	0	1092	484609
Edmonton Power						
1982(1)	0	0	0	0	59	59
1983	581	0	0	0	161	742
1984	0	0	0	8,773	142	9,342
1985	0	0	0	4,910	123	5,023
1986	0	0	0	18,866	110	19,010
1987	0	0	0	18,516	103	18,603
1988	0	0	0	9,954	106	10,106
1989	0	0	0	4,152	112	4,312
1990	0	0	0	0	117	117
1991	0	0	0	0	59	59
Subtotal	581	0	0	65171	1092	67373
TransAlta						
1982(1)	133	8,755	8,827	34,611	59	52,385
1983	720	59,236	30,839	64,745	161	155,701
1984	0	92,927	34,384	26,053	142	153,506
1985	0	120,375	41,943	26,814	123	189,255
1986	0	132,923	45,457	16,552	110	195,042
1987	0	146,529	57,550	13,087	103	217,269
1988	0	153,326	63,574	14,525	106	231,531
1989	0	137,137	66,750	6,697	112	210,696
1990	0	99,293	(1,828)	0	117	97,581
1991	0	89,048	(6,399)	0	59	82,708
Subtotal	853	1039548	341096	203084	1092	1585674
Totals:						
Including EEM Program	1,852	1,403,327	460,416	268,255	3,277	2,137,127
Excluding EEM Program	1,852	1,403,327	460,416	0	0	1,865,595

Notes
1. Natural gas price rebates are from September to December for 1982.
2. Income tax rebates include those applicable to downsteam operations; rebates in Tables B-1 to B-10 & IV-1 are confined to upstream operations.
3. EEM Agency costs allocated equally among utilities.
4. 1991 data are forecasts.
5. All data were provided by Alberta Department of Energy.

Over the life of the EEM Agency, direct costs were about $3.3 million. As discussed in Part C following, they tended to decrease over the period as Agency efficiency improved and its work load diminished.

5. Total Government Payments and Rebates

From September 1982 to June 1991, total government payments and rebates amounted to over $2 billion. TransAlta accounted for 74 percent of this amount, Alberta Power about 23 percent and Edmonton Power three percent. As mentioned earlier, most of the monies directed to TransAlta and Alberta Power were income tax rebates accounting for about 87 percent of total government payments and rebates. Virtually all of the remaining 13 percent was accounted for by the shielding program.

The total costs borne by the Alberta Government attributable to the EEM Program and shielding over the decade were some $271 million.

C. DIRECT AND INDUCED COSTS OF THE EEM PROGRAM

The costs of operating the EEM Program, including costs incurred by the utilities as a result of EEM, are discussed briefly here.

Cost data for administering the program itself (direct costs) and hearing costs absorbed by the utilities, including those recovered as PUB approved costs, plus estimated internal costs borne by the utilities, are presented in Table IV-6 for the years 1982 to 1990.

As would be expected, direct EEM Program costs tended to be highest in the initial or start-up years of the program, at nearly one-half million dollars per year. From 1985 to 1990, the last complete year that the Program was under the Agency's jurisdiction, direct costs averaged about $336 thousand.

Induced costs incurred by the three utilities[28] comprised the greatest portion of total EEM Program related costs, reaching levels of 88 to 92 percent from 1987 on. And within the induced

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[28] Estimates of internal costs were provided by the utilities.

Table IV–6

Direct and Induced Costs of EEM Program
(for the calendar year ($000))

	Direct Agency Costs (1)	Utilities Induced Costs External (2)	Utilities Induced Costs Internal (3)	Total Induced Costs (4)	Total Costs (5)
1982	177	0	595	595	772
1983	482	0	1247	1247	1729
1984	426	228	1448	1676	2102
1985	370	153	1229	1382	1752
1986	331	0	1290	1290	1621
1987	310	978	1338	2316	2626
1988	317	845	1429	2274	2591
1989	336	1853	2037	3890	4226
1990	351	717	1916	2633	2984
Total	3100	4774	12529	17303	20403

Notes: Hearing costs allocated to year in which decision was dated.
Col.(1) – Borne by Government.
Cols.(2) & (3) – Included in utility rates, and ultimately borne by consumers.

Sources: Col. (1) EEM Agency Annual Reports.
Col. (2) Public Utilities Board Exhibits.
Col. (3) Estimated by the Utilities.

category, estimated internal costs represented the largest component for all years. Total induced costs for the three utilities amounted to some $11 million during the latter part of the 1980s (1987 to 1990 inclusive). Internal costs were estimated to be 60 percent of this amount. Hearing costs were particularly onerous in 1989.

Costs absorbed by intervenors and PUB costs related to the EEM Program have not been estimated. However, discussions with the Chairwoman of the PUB indicated incremental costs associated with the EEM Program would be insignificant.

Total annual EEM Program costs grew from some three quarters of a million dollars in 1982 to over four million dollars by 1989. In 1990, costs declined. For the 1982 to 1990 period, costs totalled $20.4 million.

V. TYPICAL CUSTOMER CHARGES

The EEM Program was never intended to equalize the purchase cost of electricity by end users across the province. As discussed beforehand, the notion of equalization was confined to generation and transmission costs and did not include distribution costs.

Nevertheless, end users perception of the impact of the EEM Program are important. In conducting this study the Consultants assessed some recent (August 1991) data on 'typical' residential customer costs. Budget and timing constraints precluded a full provincial survey.

We found that the notion of the typical user was elusive, particularly for the general service and industrial categories where there is a wide range of typical energy use between utilities. In contrast, the average use of residential consumers is fairly similar among utilities.

Accordingly, in this section we focus on selected regions and compute costs for a typical residential user. Although the data used do not constitute more than a snapshot, the Consultants believe the results offer insight into the impact of the EEM Program on final electricity costs in the residential sector.[29]

We emphasize that the main purpose of this Section is to compare residential customer costs with and without the EEM Program and not to make comparisons among utilities. Meaningful comparisons among utilities are extremely difficult because retail electricity bills are affected by many factors including the timing of rate changes, rate design, differences in municipal taxes and the profits of municipal utilities. In addition, the rates of a utility are affected by its "investment policy" which sets the amount that the utility will contribute towards the costs of customer connection. The customer pays connection costs either directly or through the rates the utility charges. If a utility

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[29] The Consultants acknowledge extensive assistance from the Electricity Policy Branch, Department of Energy, in preparing the data. Advice on the profile of a typical residential customer from Alberta Power, Edmonton Power, TransAlta Utilities, and the Cities of Calgary, Edmonton, Lethbridge and Red Deer is also gratefully acknowledged.

reduces its contribution under its investment policy, its distribution costs become lower and therefore, it can lower its rates. Another factor is that each municipal utility has a different method of accounting for downstream costs, and in most cases information on customer contributions is not available.[30]

All these factors have to be taken into account when comparing consumer's electrical bills. Such analysis is complex and ideally would require participation by all the utilities and municipalities in the province. These caveats need to be kept in mind when looking at the data discussed below.

Table V-1 shows wholesale and retail purchase costs without and with the EEM program as at August 1991 for residential customers using 600 kWh of electricity per month in the communities of:

- Grande Prairie (Alberta Power);
- Edmonton;
- Calgary;
- Red Deer;
- Lethbridge; and
- TransAlta (direct).

For comparison purposes, numbers are shown for August 1982, the last month prior to the EEM Program.[31]

Currently, the EEM Program results in a 1.49 ¢/kWh reduction in final consumer costs for the average residential consumer in Alberta Power's service area and a 1.05 ¢/kWh reduction for the City of Edmonton.

The increase for residential customers in Calgary, Red Deer, Lethbridge and TransAlta's service area is 0.69 ¢/kWh.

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[30] The problems associated with comparing electrical rates among utilities apply with particular force to the general service and industrial categories.

[31] The data in Table V-1 were provided by the Department of Energy.

Table V-1

Typical Residential Customer Electric Charges
600 kWh/month
(All costs in cents/kWh)

	Grande Prairie (Alberta Power)	Edmonton	Calgary	Red Deer	Lethbridge	Communities Served Directly by TransAlta
Typical Energy Use - MWh/year	7.2	7.2	7.2	7.2	7.2	7.2
			August 1991			
Wholesale Cost at Pooling Interface						
Without EEM Program	5.84	5.40	3.66	3.66	3.66	3.66
With EEM Program	4.35	4.35	4.35	4.35	4.35	4.35
Difference in Costs	-1.49	-1.05	0.69	0.69	0.69	0.69
Costs Downstream of Pooling Interface	4.34	2.01	2.66	2.72	3.05	4.20
Consumer Cost:						
Without EEM Program	10.18	7.41	6.32	6.38	6.71	7.86
With EEM Program	8.69	6.36	7.01	7.07	7.40	8.55
Difference in Costs	-1.49	-1.05	0.69	0.69	0.69	0.69
			August 1982 (prior to EEM Program)			
Consumer Cost	7.83	4.57	4.15	3.86	4.02	5.13

Notes:
1. The costs downstream of the pooling interface include distribution costs, municipal taxes and municipal profits.
2. Each utility has its own 'investment policy' which sets the amount the utility will contribute toward the cost of connecting new customers to its distribution system. As a utility reduces the contribution under its investment policy, it lowers its distribution costs, and therefore, lowers the rates required to recover costs. The total cost of electricity includes the utility's electrical rate and the consumer's initial contribution toward the cost of connecting to the system.
3. Consumer cost does not include GST.
4. Alberta Power's electrical bills include a municipal franchise fee or tax depending on the customer's location.
5. It is assumed that changes in the wholesale cost i.e. with and without EEM Program for Edmonton, Calgary, Red Deer and Lethbridge flow through to the end user (this can be discretionary).

Source: Alberta Department of Energy.

The ratio of residential consumer costs between Alberta Power's and TransAlta's direct customers was 1.5 in 1982; in 1991 with the EEM Program that ratio had fallen to about 1.02. This indicates that the impact of the Program was visible at the retail level in the residential sector, as well as at the wholesale level.

As discussed earlier, the intention of the EEM Program was to equalize upstream costs which at the time of the Program's inception accounted for approximately 80 percent of total electricity costs in the province. The data in Table V-1 show that upstream costs account for only about 50 percent of TransAlta's and Alberta Power's residential rates.

This suggests that the share for other sectors (general service and industrial) of upstream costs in retail prices on average would be considerably less than 20 percent, reflecting lower unit costs of distribution to these customers. It follows that the EEM Program would have a greater relative influence on retail rates in the general service and industrial categories.

VI. CONCLUDING OBSERVATIONS

In light of the review of EEM impacts on the Alberta electric industry (Section IV) and the typical residential customer rate analysis is Section V, the Consultants offer the following observations. These observations should not be construed as recommendations.[32]

We again point out that the consultants were not asked to undertake a review and comparison among the utilities of electricity costs to the final consumer. These costs are affected by a host of factors in addition to the wholesale cost upon which the EEM Program was focused.

Our first set of observations (one through five) refer to the five key goals of the EEM Program cited in Section I.[33] We then make some observations on secondary aspects (six through ten).

A. PRIMARY OBSERVATIONS

1. "Fair and Equal Wholesale Rates"

The first and most important of the five key goals of the was the establishment of "fair and equal" wholesale electric rates. To what extent has this goal been attained?

The Consultants note the use of the term "rates" rather than costs or prices in defining this objective. The Consultants also note that in every year the Program, before application of shielding, resulted in equalized demand and equalized energy charges (which together comprise the rates) among the utilities at the 'pooling' interfaces. This means that the wholesale costs per unit of energy at the interfaces would be the same for comparable loads ie: for loads of equal load factor. The Consultants believe this result meets the objective of "equal" wholesale rates.

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[32] Through the terms-of-reference of the study, the Consultants are asked not to make recommendations.

[33] See Section I, p 7. The more extensive list of nine goals cited in Appendix A (pp A-6 & A-7) is also relevant.

Respecting load factors: the EEM differentiates between the residential sector, on the one hand, and the general service and industrial sectors, on the other. In effect load factors within the residential sector are averaged, while those for the general service and industrial categories are not. The Consultants believe this treatment is reasonable and appropriate since the residential sector is more homogeneous than the other sectors and the variations in load factors that do arise are more involuntary.

Shielding tempered the impact on TransAlta and Edmonton Power of cost increases caused by EEM transfers. The Consultants believe this added to the acceptability of the Program and contributed to its "fairness", since abrupt imposition of full EEM transfer costs would have been onerous, particularly on TransAlta customers.

In short, the Consultants believe the objective of "fair and equal" wholesale rates was fully achieved. This is illustrated by the situation in 1991 after shielding had ended when the wholesale costs for each utility and for each of the three customer categories were as shown below.

Wholesale Electric Energy Costs, 1991
¢/kWh

	Alberta Power	Edmonton Power	TransAlta
Residential	4.35	4.35	4.35
General Service	3.59	4.06	3.61
Large Industrial	3.29	3.05	2.93

The residential sector unit costs are exactly equal. In the General Service category, the near equal unit costs for Alberta Power and TransAlta reflect their near equal load factors. The higher cost for Edmonton Power reflects the different character (lower load factor) of its General Service market.

Similar comments apply to the variation in rates for the Large Industrial category.

2. "Most Efficient Use"

The second listed objective was assurance of the most efficient use of electric energy sources throughout Alberta. Before the start of the EEM , the utilities themselves, and through their Electric Utility Planning Council (EUPC), and the Energy Resources Conservation Board (ERCB), supported the concept of "economic dispatch" or the use of the lowest cost sources of electricity.

The Consultants have some difficulty in assessing whether the EEM has had a significant impact on economic dispatch but accept that the Program added to each utilities' concern that the other utilities operate in an efficient manner. At the same time, the Program's averaging process tends to erode individual market tests of economic efficiency, to the extent these hold under regulation.

The Consultants observe that achievement of economic dispatch essentially devolved on mechanisms other than the EEM Program itself, namely on the utilities and the EUPC in terms of co-ordination and planning, on the ERCB in approving facility construction, and on the PUB in approving rates. However, the EEM averaging process may have eased negotiations among the utilities to assure economic dispatch.

3. "Reducing the Rate of Increase in Costs"

The Consultants' comments above on "Most Efficient Use" above are also relevant to this objective. The burden for ensuring efficiency in the generation, purchasing and transmission of electric energy was mainly borne by the utilities themselves, the ERCB and the PUB. The EEM Agency's role here was minor. The Consultants do note that the average of the three utilities' cost of energy was quite stable over the 10 year period examined, and even declined in 'real' terms.

4. "Allow for Purchase of Electric Energy Beyond Alberta"

TransAlta, which effectively acts as dispatcher of electricity for the province as a whole, arranges for the export, import or exchange of electricity on behalf of the Alberta Integrated System (AIS) utilities depending on whether or not there is energy surplus to Alberta's requirements. This functior did not devolve on the

Agency. However, the Consultants observe that the EEM Program probably facilitated the contracting process, through the averaging of costs.

5. "Allow For Efficient Operation of Utilities"

The EEM Program was designed to minimize interference in utility operations. The Consultants believe it did fulfil this objective. But, as discussed in Section IV C, the Program did impose some additional costs on the utilities. In a broader sense also the cost averaging procedure of the Program could lessen market incentives for efficient utility operations, although such operations are already subject to regulation.

B. SECONDARY OBSERVATIONS

6. Trends in Rate Disparities

At the time the Program was introduced, there was an expectation that rate differentials - especially between Alberta Power and TransAlta - would widen in the future.[34] Data on what the costs might have been had the EEM Program not been introduced, broadly show a narrowing of aggregate costs among the utilities, both in relative and absolute terms. However, the Consultants also observe that since the mid 1980s, in the absence of the EEM Program the difference in residential costs at the pooling interface between Alberta Power and TransAlta has increased.

7. Role of Income Tax Rebates

The income tax rebates - especially before elimination of the provincial portion - provided a significant cost reduction to the customers of the privately owned utilities in the absence of the EEM Program and to all customers with the EEM Program.

8. The Shielding Program

The Consultants observed earlier that the shielding program contributed in an important way to the perceived fairness of the EEM Program, although at considerable cost to the Alberta taxpayer. At the same time, the various extensions to the Program illustrate

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[34] See Appendix A, p A-2.

the difficulty associated with removing subsidies, once they are instituted.

9. Balanced Economic Growth

The EEM Program was intended to contribute to more balanced economic growth in the province. Examination of this issue would require detailed analysis of location factors and the significance of electricity in industrial costs, by region. Such analysis is beyond the scope of this report.

However, the Consultants observe that industrial electricity sales in the regions served by Alberta Power grew more rapidly than elsewhere. Although this might have happened irrespective of the EEM Program, the outcome does suggest the cost reductions provided in regions with relatively high costs of electricity might have removed an impediment to growth.

10. Electricity Retail Rates

The scope of the Consultants' study did not permit a comprehensive review of the price of electricity paid by final consumers, that is of retail rates. Such rates depend not only on wholesale rates but on a host of other factors including the timing of rate changes, differences in municipal taxes and profits, investment policies, rate design, and customer load characteristics. Notwithstanding this, the impact of the EEM Program as seen in the wholesale cost is reflected in the price to the ultimate consumer, albeit subject to variations due to the factors mentioned above.

If a full review of final consumer charges were to be pursued, the Consultants observe that careful adjustments to ensure proper comparisons of retail rates would be required. Such a review might best be carried out by the Government in direct consultation with the utilities.

APPENDIX A: THE ORIGINS OF THE ELECTRIC ENERGY MARKETING PROGRAM

This appendix provides a description of the origins of the Electric Energy Marketing (EEM) Program gleaned from various documents in the files of the Department of Energy.[35]

What was seen as a compelling need for the Alberta Government to do something about electricity rate differentials in the Province emerged late in 1980. However, such concerns were not new: they were quite long standing. Studies on rate differentials - especially in the context of Northern Alberta - had been commissioned in 1977 and the problem had excited discussion in the legislature in 1979 and earlier in 1980.[36]

The review below proceeds broadly in chronological order.

1. INITIAL STUDIES

In 1979 the Alberta Department of Utilities and Telephones (ADUT) commissioned a confidential study by Foster Research of Calgary (Foster) entitled "Data Collection, Analysis and Consultation Respecting a Report on the Electric Utility Industry in Alberta". The role of the Consultant was seen as part and parcel of work the Department wanted to pursue. The intention was for Foster to analyze the basic information required to develop a comprehensive report on the industry, to provide advice on industry problems, and to analyze alternative solutions. This included legislative and regulatory implications and their effects on industry and consumers.

Eleven problem areas cited at this time included rate differentials and regulation, natural gas price and income tax rebates, franchise area allocations, hydro electric developments, the Western Power Grid, balanced economic growth, Rural Electric Associations (REAs), ownership of new facilities, export opportunities and environmental problems.

An outline of the study also identified possible remedies ranging from a 'marketing commission', provincial takeover, utility mergers, introduction of a 'generator' tax and development of new

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[35] Certain of these documents are confidential, hence some of the information in this Appendix is not referenced.

[36] Hansard, November 26, 1981, p. 1896.

government owned facilities.

In mid 1980, ADUT requested additional work from Foster on the order-of-magnitude of adjustments to residential rates if some kind of averaging scheme were implemented, and on the cost of acquiring utility generation facilities in Alberta. Estimates were made of the effect of various levels of provincial subsidy on electricity billings for various Alberta centres. The then Minister of ADUT, the Honourable Larry Shaben, was kept informed of the progress of this work.

After completion of the additional Foster work, government thinking seemed to lean toward the idea of some kind of an electric energy marketing agency. Principles governing such a body were drawn up. Its prime objective was seen as the reduction of rate differentials. However, a government subsidy, referred to as "shielding", was intended to avoid any immediate rate increases associated with equalization. The proposed agency was also seen as providing the government with a wide range of "discretionary capabilities". The agency was not intended to have a significant effect on the "well-being" of the electric utility companies.

As will be seen below, these principles provided a consistent theme underlying development of the marketing policy.

Further details on the Marketing Agency concept emerged in a position paper, prepared probably late in 1980.[37]

2. GOVERNMENT POSITION PAPER ON A MARKETING AGENCY

This document cited specific government concern about geographical differences between the amounts paid by similar electricity customers across the province (in particular the Peace River area of Northwestern Alberta).

The problem areas identified[38] were seen as likely to become increasingly serious. Problems cited included the following:

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[37] Department of Utilities and Telephones, "Electric Power Marketing Agency of Alberta", Confidential; undated.

[38] They reiterated many of those mentioned in the preamble to the first Foster Study.

- Differences in rates attributable to costs of generation, transmission and distribution.
- Differences in the level of provincial gas support price rebate assistance given to utilities.
- Reductions in federal tax rebates.
- Differences in rate regulation between certain service areas.
- Impediments to balanced economic growth imposed by differential rates.
- Differential geographical rates attributable to new facilities as a function of location.
- Financing capital expenditures and cost sharing equity between farm and non-farm customers, and delineation of responsibilities between companies and Rural Electric Associations (REAs) in rural regions.
- Integration of the import and export of electric energy.

The ADUT identified alternative remedies for these perceived ills, embracing the full spectrum from maintenance of the status quo, to government takeover of power utilities. Certain options were examined in more detail, including Government takeover, imposition of taxes on electric energy generation, provincial ownership of new facilities and a voluntary utility pooling agreement.

The solution recommended by the Minister of Utilities and Telephones (the Honourable Larry Shaben) was establishment of an Alberta Electric Energy Marketing Agency (Agency). The idea of the proposed Agency was said to owe something to the concepts underlying the Alberta Petroleum Marketing Commission (APMC).

The Agency was intended to purchase electric energy at the "difficult to define" end of transmission lines. The Agency would resell the energy to utilities at the terminus of 72 kV[39] transmission lines at an equalized rate. The procedure was expected to eliminate over 80 percent of the provincial consumer rate differentials.

The proposal was also seen as yielding advantages beyond simple rate equalization. These included simplification of any electric energy imports and exports, encouragement of more balanced

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[39] When the Program was set up this was changed to 25 kV.

growth in the province, more equitable treatment of income tax rebates, reduced significance of decisions on franchise and service area allocations, equal distribution of increased costs of expanded facilities, accommodation of government policy on electric energy rates, and partial resolution of rural electrification problems. In short, the Agency was intended to ameliorate virtually all the problems listed beforehand.

At the same time it was believed the scheme would not impinge on the Public Utilities Board (PUB) and Energy Resources Conservation Board (ERCB) roles and was expected to retain the combination of investor and publicly owned utilities and distribution systems. Subsidies were to be paid by the Government for the initial five years to shield adversely affected consumers, (mainly those of TransAlta whose generation-transmission costs were the lowest in the Province).

A tentative list of Agency functions was drawn up by the Department of Utilities and Telephones early in December, 1980.

3. THE FOSTER 1981 STUDY

Early in 1981, the ADUT commissioned another study by Foster Research of Calgary. The title of the study (completed on February 27, 1981) "Data Relating to a Review of the Proposed Electric Energy Marketing Agency Concept" belied its scope. It not only compiled critical data on electricity rates and estimated the impact on residential billing rates of the averaging of generation and transmission rates, but it also provided estimates of provincial subsidies to avoid any rate shock. More importantly, it delved into the concept of an Agency and outlined and discussed two alternative modes of operation.

As government policy making on this issue gathered momentum, the Foster Report seemed pivotal in its evolution.

Foster's comparison of electricity bills across the province was undertaken without any direct information from, or contact with, the Alberta electric utilities. This was consistent with the confidential nature of the Foster study. Reliance was placed on public information, such as utility company annual reports and information provided by utilities to regulatory authorities. Data on electricity rates for certain other centres in Canada were

compiled.

The Foster Report estimated the impact of the averaging of generation and transmission costs on residential billing rates. Estimates were also made of the required provincial subsidy if it were designed to reduce Alberta Power's (APL) and Edmonton Power's average unit cost to the level of Calgary Power's (later called TransAlta Utilities) in 1982.

Projections of energy sales, average unit energy costs and total cost of generation and transmission of all three major utilities were made for an eleven year period. These data were used to illustrate the approximate effects of both five and ten year phase-outs of provincial 'shielding'.

The Report also discussed two possible modes of operation. With the first, the Agency would be a financial middleman, managing the transfer of funds to and from individual utilities to provide for rate equalization for similar classes of electric customers throughout the province. In the second mode, the Agency would act as an energy broker and possibly as a facility owner. This idea would mean more direct Agency participation in the utility industry.

4. OTHER 1981 DEVELOPMENTS

By the summer of 1981 the objectives and operating parameters of the proposed Agency were outlined in a form to allow drafting of legislation. A plan was to be submitted to the Economic Planning and Resource Development Committee of Cabinet in mid July.

In August of 1981 a government-industry liaison/advisory committee on implementation was formed. Certain administration matters, including approval of staff requirements and a 1982-1983 budget (including subsidy provisions), were to be put forward in the Fall of 1981. The original objective was to have the legislation proclaimed by April 1, 1982, with the Agency commencing operation at that date.

The Plan submitted to the key Economic Planning Committee of Cabinet brought together the thinking which lay behind the

proposal.[40] The fragmented nature of the industry was seen as causing significant rate differentials. In addition, this 'fragmentation' did not seem to serve efficiency objectives. Studies by ADUT indicated a marketing agency (similar in concept to the APMC) as the "best way" to address present and future problems.

The Agency - which was not intended to jeopardize areas of operation where the power companies were effective and efficient - would average generation and transmission costs by imposing a postage stamp wholesale rate for electric energy. Local distribution costs would be added on. The Agency would purchase on a least-cost basis, and would be able to import electric energy. The Alberta Government could inject provincial support, allowing the Agency to exert some influence on final costs. A five year phase-in period was planned, with Government subsidies of some $100 million in the first year of operation. The subsidy on natural gas for electric energy generation was intended to be eliminated for consumption above certain levels. PUB 'rate base' regulation of utility companies was to remain and be extended to Edmonton Power's electric generation facilities.

The Agency goals stated in the Plan are listed below:

"1. Provide a basic and fair wholesale power rate for all Alberta consumers (Wholesale costs account for 80% of the final cost to the consumer).

2. Ensure a more efficient use of Alberta power sources, utilizing the least-cost sources on a province-wide basis.

3. Provide the lowest possible cost electric energy for the population of Alberta, taken as a total body.

4. Integrate any power sources purchased outside of Alberta for the benefit of all regions in Alberta.

5. Ensure that any surplus electric power which might be exported in the future will benefit Alberta consumers.

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[40] "Electric Energy Marketing Agency", undated, but presumably Summer, 1981.

6. Encourage the government's policy of balanced economic growth.

7. Equally distribute increased costs of production and transmission or introduction of new supplies of high or low-cost electric energy.

8. Help to resolve consumer concerns and the concerns of rural electrification association cooperatives with a minimum of new administration and without destroying the efficient elements of present systems.

9. Temporarily reduce energy rates to one-third of Alberta customers".[41]

Emphasis was placed on the Agency minimizing government interference and burdens on taxpayers. The major cities were expected to experience some increase in electricity costs over the short to medium term by virtue of rate levelling, but these were to be substantially offset by provincial subsidies during the first five years. In the long run Calgary and Edmonton were anticipated to benefit from more efficient power generation, via least-cost purchasing by the Agency.

In August of 1981, the Agency concept was (in confidence) 'bounced off' the cities and utilities.[42] Later that month the decision was made to engage a consultant to assist in developing the legislation and to ensure an orderly transition. The consultant's role was seen as providing key general and technical inputs, and to develop and organize a government/industry implementation committee. Such consultation would be provided over the period from September 1981 to June 1982. Mr. David Smith - later to become the first Chairman of the Agency - was selected to fulfil these tasks.

In October 1981, confidential discussions on the prospective Agency were held with the Energy Resources Conservation Board

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[41] Ibid, pp. 4,5.

[42] Interestingly, Calgary Power (later TransAlta) was reported as saying that if Calgary Power acquired Alberta Power rate equalization would be achieved without government intervention: the combined single investor owned utility would internally implement the cross-subsidization.

(ERCB), the Public Utilities Board (PUB), TransAlta Utilities, Alberta Power, the City of Edmonton and the City of Calgary.[43] It was emphasized that the Agency would not sell to ultimate customers or REAs, that no diminution of ERCB or PUB roles was foreseen, and that no ownership of power generation or transmission assets was intended.

Industry/Government Implementation Committee meetings were held covering such aspects as the possible income tax implications of pooling, the location of pooling interfaces, and the preparation of technical data to permit drafting of detailed regulations. Medicine Hat had raised the question of whether they could opt out. The Government said the scheme was intended to be optional - but no such option was intended for Edmonton.

In November 1981, Alberta Treasury had emphasized that the method of the proposed subsidy - reducing costs to the lowest cost utility levels - maximized costs to the Province. Pressure to continue rate subsidies beyond the five years was expected. Treasury hoped such pressures would be resisted. The major cost of the program to the Government was expected to be subsidies.

The ADUT spelt out in more detail what it had in mind about the Agency's role in providing for 'economic dispatch'.[44] Four levels were envisaged. The first would be within the utility. The second would be among utilities. The third would be via the Agency through monitoring and dealing with new plant requests. The fourth would be via the Agency purchasing for out-of-province sources.

In mid November, 1981, the Government made a News Release on EEM. After purchase and resale of electric energy from all Alberta sources, the Agency would set a "standard wholesale rate for Alberta consumers".[45] The five key goals for the Agency were listed as:

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[43] The City of Calgary indicated that low prices from TransAlta had enabled them to enjoy a substantial mark-up on power rates. It thought pooling would erode this latitude.

[44] Economic dispatch refers to the strict use of facilities in order of ascending cost.

[45] Government of Alberta News Release, November 16, 1981.

"1. To establish a fair and equal wholesale electric power rate to Albertans...

2. To assure the most efficient use of power sources throughout Alberta...

3. To reduce the rate of increase to Alberta consumers in their electric energy costs...

4. To allow the purchase of power outside of Alberta...

5. To allow the continued operation of utilities in the most efficient manner."[46]

The new Agency was expected to contribute to the Government objective of balanced economic growth. Minimal administration costs were anticipated.

Estimates of the contribution distribution margins made to the City of Lethbridge net revenues in 1980 were some $2 million (revenue from distribution less costs). It was not anticipated by the Government that the EEM plan would prevent the City from retaining such profits. However, in December 1981, the City of Lethbridge requested permission to opt out of the scheme, if EEM went ahead.[47]

The City of Calgary raised the question of double counting of costs respecting certain transmission facilities. One solution - but not a preferred one in the City's view - was classifying a portion of its assets as upstream of the pooling point. Its concern about this solution was the further intrusion of regulation it would represent.

In November 1981, the City of Calgary (which absorbs one-third of TransAlta's supplies) expressed opposition to the EEM Program on the grounds of adverse financial impacts on Calgary consumers. These adverse impacts related to the averaging of generation and transmission costs province-wide and removal of "a range of

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[46] Ibid.

[47] Indeed, the City suggested the Government reconsider the establishment of the EEM Program.

reasonableness" approach to cost allocation. Full compensation was requested, without attrition over time. Concern was also expressed that averaging of transmission costs would result in a an inequitable allocation of costs, given the difficulty of precisely distinguishing between transmission and distribution activities.

5. LEGISLATIVE ACTIVITY

A further light on the setting up of the Agency is shed by debates in the Legislature following the introduction of Bill 92, The Electric Energy Marketing Act (Act). The first Reading of the Bill took place on November 16, 1981.[48]

The second reading of the Act was held on November 26, 1981. By way of introduction, The Minister (The Honourable Mr. Shaben) reviewed the relationship between the utilities, the ERCB and the PUB. The ERCB played a major role in the approval of new generation plans and dealt with matters related to service area franchises and transmission lines. The Electric Utility Planning Council (EUPC) (comprising all the utilities) formulated plans to meet Alberta's future electric energy requirements. The PUB regulated the utility rates of the investor owned utilities.

It was expected that the Agency would comprise some eight to ten people. Its primary purpose would be to "purchase, pool, and resell electricity generated for the province".[49] Allusion was made to using a mechanism similar to the APMC's. The provision for a pooling interface at the point at which distribution begins, with the Agency purchasing the energy from the generating utility and then reselling it at that point to the utility, was seen as especially important because it continued a prevailing relationship between utilities and their customers. The Minister also observed that while the PUB would still determine investor owned utility revenue requirements, it would continue not to be involved in approving rates for those cities that purchase electric energy wholesale. Thus, the municipalities rate setting role was preserved. Such continuation of the status quo was believed desirable.

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[48] Hansard, November 16, 1981, p. 1639.

[49] Hansard, November 26, 1981, p. 1896.

The Minister, in discussing the purpose of establishing the Agency, referred to the number of times in his two and one-half years as Minister that the specific issue of rate differentials had arisen in the House (three times in 1979 and twice in 1980). He then referred to it as a long-standing concern. He also said that two and one-half years of close examination of the structure of rates led to the conclusion that about 60 percent of the rate differential resulted from differences in the cost of generation. The main reasons for these variations were cited as plant ages and the associated original cost, the fuel used, and plant sizes. About 20 percent on average of the differential was attributed to transmission, primarily because of varying distances. The other 20 percent occurred in distribution, with much of these differentials relating to population density.

The Agency was expected to reduce rate differentials in the province by approximately 80 percent. The five year phasing period was intended to make the impact of the new regime gradual, because some customers rates would go up and others would go down.

The Minister said that the government had considered other options. One was having a single provincial utility operate as a crown corporation. Another was the sustained injection of subsidies to particular classes of customers. The use of federal income tax rebates, repaid to the province, to force a merger of the utilities was reviewed. But "because of the nature of the industry in Alberta and how well it has served the citizens of Alberta, the marketing Agency course of action was chosen".[50]

The government also saw the marketing Agency as achieving 'economic dispatch' within the province. It was also expected that when opportunities were presented for export of surplus electricity, the pooling process would benefit all Alberta consumers rather than the consumers of an individual utility. The Agency was expected to be helpful in buying any imports of electric energy to pool with energy from Alberta generators. It was also expected that over the next ten years there would be a need to double power generation, and over the next twenty-five years to triple them. Provision of higher cost facilities to satisfy this demand was seen as being favourably effected by pooling, which would share costs equally among all customers. The fact that

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[50] Hansard, November 26, 1981, p. 1897.

decisions on which utility should build new generation plant would not be as crucial was also cited as an advantage. It was expected to be easier for the ERCB to make decisions on generating plant location and on the best possible sources of new energy supplies.

Discussion of the Bill at its Second Reading revealed that the Caucus Utilities Committee had looked at differential electricity rates among towns, cities and rural areas, and between companies. Meetings had been held with the Union of Rural Electric Associations (REAs). Inequities in the operation of rural electricity co-operatives were seen as compounded by location factors. There was a general feeling that everyone should have access to electric energy at equivalent rates.[51]

Comments were also made that the natural gas price protection plan had already created a precedent for Government action to impose equalization. Various MLAs supported the 'equity' principle, and observed that the fairness of what was proposed was consistent, for example, with the pooling of provincial royalty revenue. Reference was also made to a resolution presented in 1972 to the Legislature on the use of a provincial power grid to even out rates.[52] Apparently, briefs on the power rates issue had been made over the past seven to eight years to the Northern Alberta Development Council.[53]

In terms of impacts, the Minister cited calculations showing that by 1987, after elimination of provincial protection, a Calgary residential consumer would be paying about 13 percent more for electricity under the Agency regulations than in its absence.[54]

Medicine Hat was to be exempt from the scheme. The reason given was the very low rates in that municipality associated with its gas fired generation facilities. These were anticipated to exacerbate averaging problems if the scheme embraced Medicine Hat.[55]

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[51] Hansard, November 26, 1981, p. 1900. Comments by MLA Mrs. Cripps.

[52] Hansard, op.cit., p. 1905.

[53] Ibid, p. 1906.

[54] Ibid.

[55] Ibid.

November 30, 1981 saw the introduction of an amendment to Bill 92, concerning the procedure for handling subsidies.[56] The ensuing discussion made reference to Gas Alberta (set up to encourage rural gasification) as providing analogous treatment to averaging in its setting of rural natural gas rates. There was also reference to the analogy offered by telephone service rates.

Details were cited on rate comparisons for Grande Prairie versus Calgary versus Edmonton, with and without the proposed Agency.[57] It was also revealed that the Government had looked at several communities in testing the impact of the Agency.[58]

The Third (and final) Reading of Bill 92 was held on December 1, 1981. Minister Shaben reiterated that the Bill had four main purposes: first, to reduce electricity rate differentials; second, to move towards economic dispatch; third, to integrate intra-provincial electric energy purchases and sales; and fourth, to more easily integrate hydro generation facilities within the system.[59] He also emphasized that the process of cross-subsidization between residential and industrial customers would continue.[60]

The Act was proclaimed on April 15, 1982.

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[56] Hansard, November 30, 1981, p. 1939.

[57] Ibid, p. 1947.

[58] These communities included Edmonton, Calgary, St. Alberta, Grande Prairie, Lloydminster, Lethbridge, Spring Coulee and Acadia Valley. Ibid, p. 1948.

[59] Hansard, December 1, 1981, pp. 1999, 2000. One interesting observation made by Minister Shaben concerned the Vegreville constituency where boundaries between franchise areas had produced noticeable rate differentials (Hansard, Ibid, p. 1995).

[60] Ibid.

6. THE SPECIAL PROJECTS BRANCH REPORT DECEMBER, 1981[61]

The Agency concept was further elaborated upon in a report by the Special Projects Branch, Alberta Utilities and Telephones, dated December 1, 1981. Again it was emphasized that the object of the Agency was to help reduce the wide disparity of rates charged to similar customers in different parts of the province, while at the same time interfering as little as possible with the autonomy of the industry by keeping the administrative process simple. However, there was recognition here that through the Alberta Interconnected System the industry already effectively operated on an economic dispatch basis. The five year phase-in period during which the equalized electric energy rate would be subsidized, was reiterated. The subsidy would be progressively reduced each year. As new plants were commissioned, the costs would be rolled into the system and not absorbed by customers of an individual utility.

There was some elaboration on what was called the provision of "discretionary capabilities" in that the Agency was seen as providing the government with the ability to fund a portion of the capital requirements of high cost generation, an involvement seen as particularly applicable to hydro-electric generation. The Agency was also to be responsible for interprovincial transmission lines supplying basic or reserve electric energy on the Alberta Interconnected System.

This document also cited three major issues related to the scope of the Agency concept: rates; industry planning and expansion; and regulation.

Rate related issues included not only the substantial rate differentials existing between the three major generating utilities but also adjustments associated with the phasing out of the natural gas price protection rebate for electricity generation.

Industry planning and expansion issues concerned the management of interprovincial and international electric energy purchases and sales and the introduction of mechanisms to achieve economic dispatch in Alberta. Here, the impact of major new hydro-

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[61] Special Projects Branch, Alberta Utilities and Telephones, December 1, 1981. This report drew quite heavily on the 1981 Foster Study mentioned earlier (see Part 3 above).

electric generation projects, in terms of ownership, financing, consumer rates, and possible provincial government support or participation, were seen as important. Also relevant was the existing electric utility planning process, including the operation and ownership of thermal generation and monitoring appropriate levels of reserve capacity.

Regulatory issues included the allocation of new service areas and the varying degrees of rate regulation among investor and municipal utilities.

The Agency's administrative costs were intended to be rolled-in to the average cost of service for all electric energy in the province. It was estimated the operating cost of the Agency would not result in an increase in rates exceeding one-half of one percent.

The contemplated modus operandi for the Agency was to purchase all the electricity delivered to the town or province via all transmission lines of all utilities, excluding Medicine Hat. The purchase price would be based on costs approved by the PUB. Then the Agency would resell electricity back to the utilities at the price determined after the averaging process (including the injection of any government subsidies).

The Agency could enter into buy-sell agreements with utilities for electricity involving the proposed 'Western power grid'. The Alberta section of the proposed intertie system could be owned one hundred percent by the Agency, or jointly-owned by the Agency and the Alberta utilities. It was also expected the Agency would represent provincial interests with respect to the export and import of electric energy.

7. IMPLEMENTATION

By early December 1981, the Technical Implementation Committee was working on five year forecasts of electric energy generation and transmission financial statements and on the design of detailed regulations, accounting and reporting systems to implement the energy pooling objective of the intended Act.

At the end of December, 1981 the intention was that the

accounting reporting systems and the equalization mechanisms required for implementation of the Agency would be in place by April, 1982. The Agency organization was expected to comprise eight to ten permanent positions with the chairman, Mr. David Smith, to be appointed on February 1, 1982. Financial implications for customers of TransAlta Utilities, Edmonton Power, and Alberta Power were estimated, with a five year straight line phase out of first year 'shielding'.

A summary of the impacts of the Electric Energy Marketing Act was also provided at this time. These impacts included a positive stimulus towards balanced growth across the province, removal of location as a prime determent of electric energy costs to Alberta consumers, preservation of the opportunity for investor ownership of utilities while at the same time continuing to provide the opportunity for city governments to use electric energy distribution systems as vehicles to raise revenue. Additional impacts cited were the enhancement of the ability to achieve economic dispatch of electric energy, elimination of preferential wholesale rates paid by the City of Calgary to TransAlta Utilities, elimination of the natural gas support price rebate on gas for power generation which provided an incentive for gas fired facilities, a relative reduction in electric energy rates for farm customers, and sharing of any benefits from exports or imports across all consumers in the province.

In January 1982, the City of Calgary advocated provincial funding support over ten years and a 'tiering' mechanism to overcome any overcharging for distribution costs in the case of Calgary. Subsequently (January 29, 1982) the City presented evidence that its higher downstream distribution costs vis a vis Edmonton would lead to a situation whereby after equalization of upstream (generation and transmission) costs customer costs would be about 1 cent/kWh above Edmonton's. This was attributed to the treatment of all costs within Calgary's boundaries as downstream, whereas substantial costs within Edmonton's boundaries were treated as upstream.

Data prepared by the two major utilities (Alberta Power and TransAlta) indicated that pooling costs had substantially increased compared with the earlier Foster estimates. In mid December 1981, the ADUT undertook to integrate these forecasts. At this time, Medicine Hat was still undecided as to whether it would join. Work

proceeded on determination of the Government shielding magnitude and pattern.

By late January 1982, the Implementation Committee completed its work on costs and implementation. With an implementation date of September 1, 1982 the net government contribution - net of reduced gas support price payments - over the period to April 1986 was estimated at some $180 million. In the first year shielding would be 100 percent for TransAlta customers, declining linearly to zero after five years. A special adjustment was recommended for Calgary to recognize that that city owns facilities normally classified as transmission.[62] Predictions were also made for 1982, 1985 and 1986, of unit costs of electric energy at the pooling interface, before and after the Agency.

In February 1982, the ADUT provided some budget information at the request of the Cabinet Priorities Committee. There was discussion in this document (and elsewhere) of two pooling options. The first would establish an average pooled price equal to that of the lowest cost utility (TransAlta). Substantial government funds would be required to subsidize higher cost utilities to the TransAlta level. The second option involved calculating the average cost of power produced by all utilities in the pool, with TransAlta customers shielded to the extent of 100 percent of the price differential in year 1, 80 percent in year 2, and so on. Higher cost utilities would purchase electric energy at the provincial average. Lower cost utilities would purchase at a price that reflects the decrease in government subsidy. The second option (which reduced government funding) was recommended.

Another point raised with the Implementation Committee by the City of Red Deer was whether transformers were part of the transmission or distribution system.

In a communication with the City of Lethbridge (February 17, 1982) the Honourable Larry Shaben, Minister of Utilities and Telephones, said that the reason for treating Medicine Hat as an exception under the Act was recognition of its ownership of natural

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[62] If this were not done - it was argued - Calgary customers could end up bearing some specific costs over and above those borne by any other customer group. Such extra costs were estimated as 0.5 cents per kWh.

gas. But any decision to opt out would be considered final. Lethbridge was seen as quite dissimilar to Medicine Hat; no such option was expected to be given to Lethbridge.

David Smith recommended (February 18, 1982) that the City of Calgary Electric System receive compensation of 0.4 cents per kWh on TransAlta sales for its ownership of certain transmission assets, until March 31, 1983. Subsequently, more permanent arrangements were intended.

By the end of February, the Provincial Government had agreed that some recognition in the Program must be given to transmission components in Calgary's system. At this time, the Province rejected the 10 year shielding period in favour of retaining its preference for five years.

In early March 1982, the need was mooted for a PUB/ERCB hearing to establish generation-transmission cost-of-service, approved rates for sales to the Agency, and final customer rates for distributors.

Answers to questions raised in the Legislature in late March confirmed that the Agency would consist of no more than eight persons during the first five years, with Agency costs to be borne directly by the Government.

A document was prepared in April for prospective tabling in the Legislature. This document was to cover the background of the industry, the regulation of public utilities, the concept of cost averaging and the role of the Agency. There was little new in the document, save that the implementation date of the Agency was set as September 1, 1982. The expected government subsidy in the initial year of operation was $72 million, with total shielding costs expected to be $320 million until the subsidy ended in 1987. Over the five year period of subsidization, customers of Alberta Power were anticipated to benefit substantially, those of Edmonton Power would share in benefits, while TransAlta customers would pay moderately more. This paper seems to have remained an internal document.

The City of Red Deer made representation in late April 1982, to receive similar concessions to those awarded the City of Calgary (relating to transmission costs). Lethbridge was also seeking

transmission compensation. Subsequently, it was agreed that compensation would be awarded to Red Deer and Lethbridge, as well as to Calgary.

In mid summer 1982, the subject of co-generation and use of small renewable resource sources for electricity generation for the Alberta Interconnected System had arisen in the context of Agency operations. A policy document was to be drafted.

Implementation of the Agency Plan introduced questions about the treatment of income tax rebates relating to deferred taxes. TransAlta, for example, believed any such rebates relating to taxes in prior years (1980 and 1981) should not be distributed by the Agency.

A summary of the Agency role was prepared in September 1982, to coincide with the inception of Agency operations. Most of the document repeated earlier material. Two offices were set up, one in Calgary, one in Edmonton, with the Chairman based in Calgary. Monthly billings and remittances were to be issued to utilities.

The end of September, 1982, saw the preparation of an Operational Plan for the Agency covering major projects and normal duties. Major projects included new five year projections of electric utility rate changes, negotiations on compensation for Calgary, Red Deer and Lethbridge ownership of transmission assets, studies on rate design to achieve 'economic dispatch', preparation of a policy document on co-generation and alternative fuel supply sources aspects, examination of export opportunities and examination of criteria for specific dedication of major generation facilities to industrial consumers. Normal duties included accounting and administration, but also related to monitoring of PUB and ERCB applications and decisions (plus relevant ones in other jurisdictions), and the monitoring of shielding grants.

The Agency began operations on September 1, 1982.

APPENDIX B:
KEY ANNUAL GENERATION AND TRANSMISSION STATISTICS FOR THE ALBERTA ELECTRIC INDUSTRY, 1982 - 1991

Table B-1

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1982

		Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales									
1	Electricity Generated, GWh	4,618		1,616		17,982		24,216	
2	Electricity Sales, GWh	3,368		4,886		15,183		23,436	
3	Electricity Demand, MW	539		836		2,396		3,771	
4	Load Factor (%)	71.3		66.7		72.3		70.9	
Basic G & T Data at Pooling Interface		($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)
5	Actual Cost	175.5	5.21	201.3	4.12	369.3	2.43	746.2	3.18
6	Natural Gas Rebate	-0.1	0.00	0.0	0.00	-0.1	0.00	-0.2	0.00
7	Income Tax Rebate	-18.1	-0.54	-9.6	-0.20	-38.9	-0.26	-66.6	-0.28
8	Cost After Rebates	157.3	4.67	191.8	3.92	330.2	2.18	679.4	2.90
9	EEM Agency Transfers	-20.1	-0.60	-14.5	-0.30	34.6	0.23	0.1	0.00
10	Cost After Transfers	137.3	4.08	177.3	3.63	364.8	2.40	679.4	2.90
11	Government Shielding	0.0	0.00	0.0	0.00	-34.6	-0.23	-34.6	-0.15
12	Cost After Transfers & Shielding	137.3	4.08	177.3	3.63	330.2	2.18	644.8	2.75
Residential Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1982							
13	Electricity Sales, GWh								
14	Cost After Rebates								
15	Costs After EEM Agency Transfers								
16	Cost After Transfers & Shielding								
General Service Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1982							
17	Electricity Sales, GWh								
18	Cost After Rebates								
19	Costs After EEM Agency Transfers								
20	Cost After Transfers & Shielding								
Large Industrial Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1982							
21	Electricity Sales, GWh								
22	Cost After Rebates								
23	Costs After EEM Agency Transfers								
24	Cost After Transfers & Shielding								

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.
The 1982 data for transfers and Shielding are for September to December only.
All other data are for the full year.

Source: Alberta Department of Energy

Table B-2

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1983

		Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales									
1	Electricity Generated, GWh	5,176		1,130		19,541		25,847	
2	Electricity Sales, GWh	3,532		4,860		15,945		24,336	
3	Electricity Demand, MW	543		838		2,433		3,814	
4	Load Factor (%)	74.2		66.2		74.8		72.8	
Basic G & T Data at Pooling Interface		($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)
5	Actual Cost	201.9	5.72	201.1	4.14	526.9	3.30	929.9	3.82
6	Natural Gas Rebate	-0.3	-0.01	-0.6	-0.01	-0.7	0.00	-1.6	-0.01
7	Income Tax Rebate	-28.1	-0.79	-13.4	-0.28	-72.7	-0.46	-114.2	-0.47
8	Cost After Rebates	173.5	4.91	187.1	3.85	453.5	2.84	814.0	3.35
9	EEM Agency Transfers	-56.6	-1.60	-12.4	-0.26	69.0	0.43	0.0	0.00
10	Cost After Transfers	116.9	3.31	174.7	3.60	522.5	3.28	814.0	3.35
11	Government Shielding	0.0	0.00	0.0	0.00	-64.7	-0.41	-64.7	-0.27
12	Cost After Transfers & Shielding	116.9	3.31	174.7	3.60	457.8	2.87	749.3	3.08
Residential Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1983							
13	Electricity Sales, GWh								
14	Cost After Rebates								
15	Costs After EEM Agency Transfers								
16	Cost After Transfers & Shielding								
General Service Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1983							
17	Electricity Sales, GWh								
18	Cost After Rebates								
19	Costs After EEM Agency Transfers								
20	Cost After Transfers & Shielding								
Large Industrial Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1983							
21	Electricity Sales, GWh								
22	Cost After Rebates								
23	Costs After EEM Agency Transfers								
24	Cost After Transfers & Shielding								

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-3

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1984

		Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales									
1	Electricity Generated, GWh	4,834		395		22,676		27,905	
2	Electricity Sales, GWh	3,635		4,687		16,316		24,638	
3	Electricity Demand, MW	583		864		2,622		4,069	
4	Load Factor (%)	71.2		61.9		71.0		69.1	
Basic G & T Data at Pooling Interface		($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	(c/kWh)
5	Actual Cost	204.5	5.63	176.5	3.77	609.0	3.73	990.0	4.02
6	Natural Gas Rebate	----	----------	-------	eliminated		----------	----------	----
7	Income Tax Rebate	-37.2	-1.02	-14.1	-0.30	-100.0	-0.61	-151.3	-0.61
8	Cost After Rebates	167.3	4.60	162.5	3.47	509.0	3.12	838.8	3.40
9	EEM Agency Transfers	-46.7	-1.28	11.5	0.25	35.2	0.22	0.0	0.00
10	Cost After Transfers	120.6	3.32	174.0	3.71	544.2	3.34	838.8	3.40
11	Government Shielding	0.0	0.00	-8.8	-0.19	-26.1	-0.16	-34.9	-0.14
12	Cost After Transfers & Shielding	120.6	3.32	165.2	3.52	518.1	3.18	803.9	3.26
Residential Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1984							
13	Electricity Sales, GWh								
14	Cost After Rebates								
15	Costs After EEM Agency Transfers								
16	Cost After Transfers & Shielding								
General Service Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1984							
17	Electricity Sales, GWh								
18	Cost After Rebates								
19	Costs After EEM Agency Transfers								
20	Cost After Transfers & Shielding								
Large Industrial Sales & Costs at Pooling Interface		NOT APPLICABLE IN 1984							
21	Electricity Sales, GWh								
22	Cost After Rebates								
23	Costs After EEM Agency Transfers								
24	Cost After Transfers & Shielding								

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-4

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1985

		Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales									
1	Electricity Generated, GWh	5,045		382		24,566		29,993	
2	Electricity Sales, GWh	4,336		5,082		18,466		27,884	
3	Electricity Demand, MW	703		925		2,823		4,451	
4	Load Factor (%)	70.4		62.7		74.7		71.5	
Basic G & T Data at Pooling Interface		($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	c/kWh)	($MM)	(c/kWh)
5	Actual Cost	200.8	4.63	179.99	3.54	672.83	3.64	1053.58	3.78
6	Natural Gas Rebate	------	--------	---------	eliminated	------	-------	---------	-------
7	Income Tax Rebate	-37.5	-0.86	-13.3	-0.26	-128.0	-0.69	-178.7	-0.64
8	Cost After Rebates	163.3	3.77	166.7	3.28	544.9	2.95	874.9	3.14
9	EEM Agency Transfers	-26.6	-0.61	8.2	0.16	18.4	0.10	0.0	0.00
10	Cost After Transfers	136.8	3.15	174.9	3.44	563.2	3.05	874.9	3.14
11	Government Shielding	0.0	0.00	-4.9	-0.10	-26.8	-0.15	-31.7	-0.11
12	Cost After Transfers & Shielding	136.8	3.15	170.0	3.34	536.4	2.91	843.2	3.02
Residential Sales & Costs at Pooling Interface									
13	Electricity Sales, GWh	1,070		1,273		4,161		6,504	
14	Cost After Rebates	54.2	5.07	48.7	3.82	179.4	4.31	282.3	4.34
15	Costs After EEM Agency Transfers	46.5	4.34	55.3	4.34	180.6	4.34	282.3	4.34
16	Cost After Transfers & Shielding	46.5	4.34	51.3	4.03	174.4	4.19	272.2	4.18
General Service Sales & Costs at Pooling Interface									
17	Electricity Sales, GWh	2,010		3,231		7,871		13,112	
18	Cost After Rebates	72.4	3.60	104.0	3.22	212.8	2.70	389.2	2.97
19	Costs After EEM Agency Transfers	59.2	2.94	105.0	3.25	225.0	2.86	389.2	2.97
20	Cost After Transfers & Shielding	59.2	2.94	104.4	3.23	210.5	2.67	374.1	2.85
Large Industrial Sales & Costs at Pooling Interface									
21	Electricity Sales, GWh	1,257		578		6,434		8,269	
22	Cost After Rebates	36.7	2.92	14.0	2.43	152.6	2.37	203.3	2.46
23	Costs After EEM Agency Transfers	31.1	2.47	14.6	2.52	157.7	2.45	203.3	2.46
24	Cost After Transfers & Shielding	31.1	2.47	14.2	2.46	151.5	2.35	196.8	2.38

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-5

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1986

	Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales								
1 Electricity Generated, GWh	5,429		121		26,605		32,155	
2 Electricity Sales, GWh	4,790		5,230		18,802		28,822	
3 Electricity Demand, MW	750		831		2,662		4,244	
4 Load Factor (%)	72.93		71.81		80.62		77.54	
Basic G & T Data at Pooling Interface	($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	c/kWh)	($MM)	(c/kWh)
5 Actual Cost	238.1	4.97	153.6	2.94	740.6	3.94	1132.3	3.93
6 Natural Gas Rebate	------	--------	---------	eliminated	------	-------	---------	-------
7 Income Tax Rebate	-37.0	-0.77	-11.8	-0.23	-153.9	-0.82	-202.8	-0.70
8 Cost After Rebates	201.1	4.20	141.8	2.71	586.7	3.12	929.5	3.22
9 EEM Agency Transfers	-37.8	-0.79	35.4	0.68	2.4	0.01	0.0	0.00
10 Cost After Transfers	163.2	3.41	177.1	3.39	589.1	3.13	929.5	3.22
11 Government Shielding	0.0	0.00	-18.9	-0.36	-16.6	-0.09	-35.4	-0.12
12 Cost After Transfers & Shielding	163.2	3.41	158.3	3.03	572.6	3.05	894.1	3.10
Residential Sales & Costs at Pooling Interface								
13 Electricity Sales, GWh	1,084		1,297		4,135		6,516	
14 Cost After Rebates	55.9	5.16	39.9	3.08	173.0	4.18	268.9	4.13
15 Costs After EEM Agency Transfers	44.7	4.13	53.5	4.12	170.6	4.13	268.9	4.13
16 Cost After Transfers & Shielding	44.7	4.13	46.2	3.56	167.2	4.04	258.1	3.96
General Service Sales & Costs at Pooling Interface								
17 Electricity Sales, GWh	2,260		3,352		8,038		13,650	
18 Cost After Rebates	86.4	3.82	88.9	2.65	235.5	2.93	410.8	3.01
19 Costs After EEM Agency Transfers	67.3	2.98	107.2	3.20	236.2	2.94	410.8	3.01
20 Cost After Transfers & Shielding	67.3	2.98	97.5	2.91	229.0	2.85	393.7	2.88
Large Industrial Sales & Costs at Pooling Interface								
21 Electricity Sales, GWh	1,446		581		6,629		8,656	
22 Cost After Rebates	58.7	4.06	12.9	2.23	178.2	2.69	249.9	2.89
23 Costs After EEM Agency Transfers	51.2	3.54	16.4	2.82	182.3	2.75	249.9	2.89
24 Cost After Transfers & Shielding	51.2	3.54	14.5	2.50	176.4	2.66	242.2	2.80

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-6

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1987

	Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales								
1 Electricity Generated, GWh	6,390		482		26,283		33,155	
2 Electricity Sales, GWh	5,166		5,313		19,675		30,154	
3 Electricity Demand, MW	746		815		2,666		4,227	
4 Load Factor (%)	79.1		74.5		84.2		81.4	
Basic G & T Data at Pooling Interface	($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	c/kWh)	($MM)	(c/kWh)
5 Actual Cost	282.3	5.46	132.9	2.50	781.2	3.97	1196.4	3.97
6 Natural Gas Rebate	------	--------	---------	eliminated	------	-------	---------	-------
7 Income Tax Rebate	-43.0	-0.83	-7.1	-0.13	-158.0	-0.80	-208.1	-0.69
8 Cost After Rebates	239.3	4.63	125.9	2.37	623.2	3.17	988.3	3.28
9 EEM Agency Transfers	-64.2	-1.24	55.6	1.05	8.6	0.04	0.0	0.00
10 Cost After Transfers	175.1	3.39	181.4	3.41	631.8	3.21	988.3	3.28
11 Government Shielding	0.0	0.00	-18.5	-0.35	-13.1	-0.07	-31.6	-0.10
12 Cost After Transfers & Shielding	175.1	3.39	162.9	3.07	618.7	3.14	956.7	3.17
Residential Sales & Costs at Pooling Interface								
13 Electricity Sales, GWh	1,060		1,279		4,138		6,477	
14 Cost After Rebates	58.3	5.50	33.8	2.64	157.1	3.80	249.2	3.85
15 Costs After EEM Agency Transfers	40.8	3.85	49.2	3.85	159.2	3.85	249.2	3.85
16 Cost After Transfers & Shielding	40.8	3.85	44.1	3.45	155.7	3.76	240.6	3.71
General Service Sales & Costs at Pooling Interface								
17 Electricity Sales, GWh	2,344		3,388		8,431		14,163	
18 Cost After Rebates	107.6	4.59	79.5	2.35	268.1	3.18	455.2	3.21
19 Costs After EEM Agency Transfers	76.1	3.25	113.7	3.36	265.5	3.15	455.2	3.21
20 Cost After Transfers & Shielding	76.1	3.25	102.3	3.02	261.5	3.10	439.8	3.11
Large Industrial Sales & Costs at Pooling Interface								
21 Electricity Sales, GWh	1,761		646		7,107		9,514	
22 Cost After Rebates	73.4	4.17	12.5	1.94	198.0	2.79	283.9	2.98
23 Costs After EEM Agency Transfers	58.2	3.30	18.5	2.87	207.2	2.91	283.9	2.98
24 Cost After Transfers & Shielding	58.2	3.30	16.5	2.56	201.6	2.84	276.3	2.90

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-7

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1988

		Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales									
1	Electricity Generated, GWh	7,159		1,428		27,765		36,352	
2	Electricity Sales, GWh	5,953		5,560		21,503		33,016	
3	Electricity Demand, MW	816		853		3,243		4,912	
4	Load Factor (%)	83.3		74.4		75.7		76.7	
Basic G & T Data at Pooling Interface		($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	c/kWh)	($MM)	(c/kWh)
5	Actual Cost	314.9	5.29	130.4	2.35	771.6	3.59	1216.9	3.69
6	Natural Gas Rebate	------	--------	---------	eliminated	------	-------	---------	-------
7	Income Tax Rebate	-48.9	-0.82	-6.9	-0.12	-191.2	-0.89	-247.0	-0.75
8	Cost After Rebates	266.0	4.47	123.5	2.22	580.4	2.70	969.9	2.94
9	EEM Agency Transfers	-91.2	-1.53	49.8	0.90	41.4	0.19	0.0	0.00
10	Cost After Transfers	174.8	2.94	173.3	3.12	621.8	2.89	969.9	2.94
11	Government Shielding	0.0	0.00	-10.0	-0.18	-14.5	-0.07	-24.5	-0.07
12	Cost After Transfers & Shielding	174.8	2.94	163.4	2.94	607.3	2.82	945.5	2.86
Residential Sales & Costs at Pooling Interface									
13	Electricity Sales, GWh	1,090		1,324		4,371		6,785	
14	Cost After Rebates	59.1	5.42	30.4	2.30	121.1	2.77	210.6	3.10
15	Costs After EEM Agency Transfers	33.8	3.10	41.1	3.10	135.7	3.10	210.6	3.10
16	Cost After Transfers & Shielding	33.8	3.10	39.0	2.94	131.2	3.00	204.0	3.01
General Service Sales & Costs at Pooling Interface									
17	Electricity Sales, GWh	2,614		3,603		9,146		15,363	
18	Cost After Rebates	115.2	4.41	81.2	2.25	271.1	2.96	467.6	3.04
19	Costs After EEM Agency Transfers	75.3	2.88	115.3	3.20	277.0	3.03	467.6	3.04
20	Cost After Transfers & Shielding	75.3	2.88	108.5	3.01	272.7	2.98	456.5	2.97
Large Industrial Sales and Costs at Pooling Interface									
21	Electricity Sales, GWh	2,249		633		7,984		10,865	
22	Cost After Rebates	91.7	4.08	11.9	1.87	188.2	2.36	291.8	2.68
23	Costs After EEM Agency Transfers	65.7	2.92	16.9	2.67	209.2	2.62	291.8	2.68
24	Cost After Transfers & Shielding	65.7	2.92	15.9	2.51	203.4	2.55	284.9	2.62

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-8

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1989

Generation & Sales	Alberta Power		Edmonton Power		TransAlta		Total	
1 Electricity Generated, GWh	7,819		4,503		27,099		39,421	
2 Electricity Sales, GWh	6,335		5,744		22,297		34,376	
3 Electricity Demand, MW	861		898		2,989		4,749	
4 Load Factor (%)	84.0		73.0		85.2		82.6	
Basic G & T Data at Pooling Interface	**($MM)**	**(c/kWh)**	**($MM)**	**(c/kWh)**	**($MM)**	**c/kWh)**	**($MM)**	**(c/kWh)**
5 Actual Cost	341.7	5.39	132.5	2.31	773.8	3.47	1248.0	3.63
6 Natural Gas Rebate	------	--------	---------	eliminated	------	-------	---------	-------
7 Income Tax Rebate	-52.9	-0.83	-3.0	-0.05	-175.6	-0.79	-231.4	-0.67
8 Cost After Rebates	288.8	4.56	129.5	2.25	598.2	2.68	1016.5	2.96
9 EEM Agency Transfers	-99.6	-1.57	49.8	0.87	49.8	0.22	0.0	0.00
10 Cost After Transfers	189.2	2.99	179.4	3.12	648.0	2.91	1016.5	2.96
11 Government Shielding	0.0	0.00	-4.2	-0.07	-6.7	-0.03	-10.9	-0.03
12 Cost After Transfers & Shielding	189.2	2.99	175.2	3.05	641.3	2.88	1005.7	2.93
Residential Sales & Costs at Pooling Interface								
13 Electricity Sales, GWh	1,149		1,385		4,583		7,117	
14 Cost After Rebates	63.7	5.54	32.7	2.36	145.8	3.18	242.2	3.40
15 Costs After EEM Agency Transfers	39.1	3.40	47.1	3.40	156.0	3.40	242.2	3.40
16 Cost After Transfers & Shielding	39.1	3.40	45.9	3.32	154.5	3.37	239.5	3.37
General Service Sales & Costs at Pooling Interface								
17 Electricity Sales, GWh	2,616		3,729		9,438		15,783	
18 Cost After Rebates	116.5	4.45	84.5	2.27	260.9	2.76	462.0	2.93
19 Costs After EEM Agency Transfers	73.2	2.80	115.2	3.09	273.6	2.90	462.0	2.93
20 Cost After Transfers & Shielding	73.2	2.80	112.7	3.02	271.3	2.87	457.1	2.90
Large Industrial Sales & Costs at Pooling Interface								
21 Electricity Sales, GWh	2,570		632		8,276		11,478	
22 Cost After Rebates	108.6	4.23	12.3	1.94	191.5	2.31	312.3	2.72
23 Costs After EEM Agency Transfers	76.9	2.99	17.0	2.69	218.4	2.64	312.3	2.72
24 Cost After Transfers & Shielding	76.9	2.99	16.6	2.63	215.5	2.60	309.0	2.69

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-9

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1990

		Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales									
1	Electricity Generated, GWh	7,190		4,261		27,635		39,086	
2	Electricity Sales, GWh	6,545		5,924		23,143		35,611	
3	Electricity Demand, MW	862		921		3,084		4,867	
4	Load Factor (%)	86.7		73.4		85.7		83.5	
Basic G & T Data at Pooling Interface		($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	c/kWh)	($MM)	(c/kWh)
5	Actual Cost	351.6	5.37	209.5	3.54	779.7	3.37	1340.7	3.76
6	Natural Gas Rebate	------	--------	---------	eliminated	------	-------	---------	-------
7	Income Tax Rebate	-39.3	-0.60	-1.3	-0.02	-67.8	-0.29	-108.5	-0.30
8	Cost After Rebates	312.3	4.77	208.1	3.51	711.9	3.08	1232.3	3.46
9	EEM Agency Transfers	-91.5	-1.40	15.2	0.26	76.3	0.33	0.0	0.00
10	Cost After Transfers	220.8	3.37	223.3	3.77	788.2	3.41	1232.3	3.46
11	Government Shielding	------	--------	---------	eliminated	------	-------	---------	-------
12	Cost After Transfers & Shielding	220.8	3.37	223.3	3.77	788.2	3.41	1232.3	3.46
Residential Sales & Costs at Pooling Interface									
13	Electricity Sales, GWh	1,138		1,394		4,612		7,144	
14	Cost After Rebates	70.4	6.18	52.1	3.73	184.3	4.00	306.7	4.29
15	Costs After EEM Agency Transfers	48.9	4.29	59.9	4.29	198.0	4.29	306.7	4.29
16	Cost After Transfers & Shielding	48.9	4.29	59.9	4.29	198.0	4.29	306.7	4.29
General Service Sales & Costs at Pooling Interface									
17	Electricity Sales, GWh	2,718		3,850		9,858		16,426	
18	Cost After Rebates	134.0	4.93	136.6	3.55	306.2	3.11	576.9	3.51
19	Costs After EEM Agency Transfers	91.7	3.37	143.3	3.72	341.9	3.47	576.9	3.51
20	Cost After Transfers & Shielding	91.7	3.37	143.3	3.72	341.9	3.47	576.9	3.51
Large Industrial Sales & Costs at Pooling Interface									
21	Electricity Sales, GWh	2,688		679		8,673		12,040	
22	Cost After Rebates	107.9	4.01	19.4	2.86	221.3	2.55	348.7	2.90
23	Costs After EEM Agency Transfers	80.3	2.99	20.2	2.97	248.3	2.86	348.7	2.90
24	Cost After Transfers & Shielding	80.3	2.99	20.2	2.97	248.3	2.86	348.7	2.90

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy

Table B-10

Key Generation & Transmission (G&T) Statistics
Alberta Electrical Industry, Calendar Year 1991, Forecast

		Alberta Power		Edmonton Power		TransAlta		Total	
Generation & Sales									
1	Electricity Generated, GWh	8,174		4,971		29,341		42,486	
2	Electricity Sales, GWh	7,534		6,043		25,097		38,674	
3	Electricity Demand, MW	997		978		3,209		5,184	
4	Load Factor (%)	86.2		70.5		89.3		85.2	
Basic G & T Data at Pooling Interface		($MM)	(c/kWh)	($MM)	(c/kWh)	($MM)	c/kWh)	($MM)	(c/kWh)
5	Actual Cost	390.2	5.18	299.3	4.95	835.2	3.33	1524.8	3.94
6	Natural Gas Rebate	------	--------	---------	eliminated	------	-------	---------	-------
7	Income Tax Rebate	-31.8	-0.42	-2.8	-0.05	-104.6	-0.42	-139.2	-0.36
8	Cost After Rebates	358.4	4.76	296.5	4.91	730.6	2.91	1385.6	3.58
9	EEM Agency Transfers	-89.2	-1.18	-53.9	-0.89	143.1	0.57	0.0	0.00
10	Cost After Transfers	269.2	3.57	242.7	4.02	873.7	3.48	1385.6	3.58
11	Government Shielding	------	--------	---------	eliminated	------	-------	---------	-------
12	Cost After Transfers & Shielding	269.2	3.57	242.7	4.02	873.7	3.48	1385.6	3.58
Residential Sales & Costs at Pooling Interface									
13	Electricity Sales, GWh	1,202		1,474		4,865		7,541	
14	Cost After Rebates	70.2	5.84	79.5	5.40	178.3	3.66	328.0	4.35
15	Costs After EEM Agency Transfers	52.3	4.35	64.1	4.35	211.6	4.35	328.0	4.35
16	Cost After Transfers & Shielding	52.3	4.35	64.1	4.35	211.6	4.35	328.0	4.35
General Service Sales & Costs at Pooling Interface									
17	Electricity Sales, GWh	2,878		3,874		10,190		16,942	
18	Cost After Rebates	139.4	4.84	191.9	4.95	297.7	2.92	629.0	3.71
19	Costs After EEM Agency Transfers	103.3	3.59	157.4	4.06	368.3	3.61	629.0	3.71
20	Cost After Transfers & Shielding	103.3	3.59	157.4	4.06	368.3	3.61	629.0	3.71
Large Industrial Sales & Costs at Pooling Interface									
21	Electricity Sales, GWh	3,454		696		10,042		14,192	
22	Cost After Rebates	148.9	4.31	25.2	3.61	254.7	2.54	428.7	3.02
23	Costs After EEM Agency Transfers	113.7	3.29	21.2	3.05	293.8	2.93	428.7	3.02
24	Cost After Transfers & Shielding	113.7	3.29	21.2	3.05	293.8	2.93	428.7	3.02

Notes: Cities Compensation is included in TransAlta's transfers.
Cents/kWh calculations are based on electricity sales at the pooling interface.
Income tax rebate is only for upstream costs.

Source: Alberta Department of Energy